BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner

In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota

ISSUE DATE: August 1, 2008

DOCKET NO. E-017/GR-07-1178

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings

On October 1, 2007, Otter Tail Corporation d/b/a Otter Tail Power Company (Otter Tail or the Company) filed this general rate case seeking an annual rate increase of some $14,509,521. The filing included a proposed interim rate schedule.

On November 13, 2007, the Commission issued two orders in this case finding the rate case filing substantially complete, suspending the proposed final rates, and referring the case to the Office of Administrative Hearings for contested case proceedings.

On November 27, 2007, the Commission issued an order in this case granting the Company's request for an across-the-board interim rate increase of some $7,125,147 per year, for service rendered on or after November 30, 2007. Interim rates are collected subject to refund under Minn. Stat. § 216B.16, subd. 3.

Also on November 27, 2007, the Commission issued an order setting a new base cost of energy for the period during which interim rates would be in effect.[1] Under Minn. Rules 7825.2390 *et seq.*, the base cost of energy is the cost of energy built into base rates; it is the starting point for monthly rate adjustments to reflect fluctuations in the actual cost of energy.

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[1] *In the Matter of Otter Tail Power Company's Petition for a Change in Base Cost of Energy*, Docket No. E-017/MR-07-1220, Order Setting New Base Cost of Energy (November 27, 2007).

II. The Parties and Their Representatives

The following parties appeared in this case:

- Otter Tail Corporation d/b/a Otter Tail Power Company, represented by Bruce Gerhardson, Associate General Counsel, Otter Tail Power Company, 215 South Cascade Street, Fergus Falls, Minnesota 56537; and Michael J. Bradley and Richard J. Johnson, Attorneys at Law, Moss & Barnett PA, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402.

- The Office of Energy Security of the Minnesota Department of Commerce (OES), represented by Valerie Means and Karen Finstad Hammel, Assistant Attorneys General, 1400 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101.

- The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG), represented by Ronald M. Giteck, Assistant Attorney General, 900 Bremer Tower, 445 Minnesota Street, St. Paul, Minnesota 55101.

- Enbridge Energy Limited Partnership and Enbridge Energy Company, Inc. (Enbridge), represented by Robert S. Lee and Andrew P. Moratzka, Attorneys at Law, Mackall, Crounse & Moore, PLC, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, Minnesota 55402-2859.

- The Minnesota Chamber of Commerce (MCC) and AG Processing, Inc., individually represented by Richard Savelkoul, Attorney at Law, Felhaber, Larson, Fenlon & Vogt, P.A. 444 Cedar Street, Suite 2100, St. Paul, Minnesota 55101-2136.

- Jonathan M. Drews, Otter Tail Power ratepayer and shareholder, representing himself, P.O. Box 230, Fergus Falls, Minnesota 56538-0230.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Steve M. Mihalchick to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in St. Paul on March 17-21 and April 3-4, 2008.

The ALJ held four public hearings at the following locations between February 5 and February 7, 2008:

- Bemidji City Hall
- Morris City Hall
- Fergus Falls City Council Chambers
- Youngquist Auditorium, University of Minnesota in Crookston

A total of 14 members of the public spoke at the public hearings, focusing primarily on the following subject areas:

- the importance to the service area of the Company's economic development program
- balancing the interests of shareholders and ratepayers in setting rates
- the ability of large general service customers to absorb proposed rate increases
- promoting greater reliance on wind generation
- the Company's purchase of unregulated businesses and its potential impact on rates
- the operation of the fuel adjustment clause, how energy costs are assigned to retail customers, and how the ratemaking process works

IV. Proceedings Before the Commission

On June 17, 2008, the Administrative Law Judge filed his Findings of Fact, Conclusions and Recommendation (the ALJ's Report).

On June 27, 2008, all parties filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. Rules, part 7829.2700.

On July 2, 2008, the Company filed an objection and motion to strike or exclude (a) tables 1 through 4 and related discussion in the RUD-OAG's exceptions, stating that this material had been excluded from the evidentiary record as untimely by the Administrative Law Judge, and (b) a lengthy quotation in the exceptions of Jonathan M. Drews, stating that the quotation should have been introduced as part of the evidentiary record.

On July 3, 2008, RUD-OAG replied to the Company's July 2 motion.

On July 8 and 10, 2008, the Commission held oral argument, and the record closed under Minn. Stat. § 14.61, subd. 2 on July 10.

Having examined the entire record herein, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers . . . ", citing Minn. Stat. § 216B.16, subd. 6. That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. . . .

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the diverse tasks of determining (a) the accuracy and validity of claimed costs; (b) their prudence and reasonableness; and (c) their compatibility with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, ranging from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained:

[2] Minn. Stat. § 216B.16, subd. 4, 5, and 6.

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.
>
> *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4. Any doubt as to reasonableness is to be resolved in favor of the consumer. Minn. Stat. § 216B.03.

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the “just and reasonable” standard set by statute. As the Supreme Court has explained:

> [1] A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). “Preponderance of the evidence” is defined for ratemaking proceedings as “whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates.” (Citation omitted.)

In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota, 435 N.W.2d 550, 554 (Minn.App. 1989).

II. Summary of the Issues

The parties worked effectively to narrow the issues and ultimately litigated approximately 30 issues, listed below by substantive area:

Corporate and Interstate Cost Allocations

- *Corporate Cost Allocations* – Should the Company be permitted to allocate corporate costs to its utility operating division using the alternative allocation method it proposed, or should it be required to use the default allocation method set forth in the Commission's general cost allocations orders? Do Company cost allocation practices require further examination in the context of a stakeholder workgroup?

- *Allocating the Costs of 41.6 kV and 69 kV Transmission Lines Between State Jurisdictions* – How should responsibility for the costs of these lower-voltage transmission lines be allocated among Otter Tail's customer bases in Minnesota, North Dakota, and South Dakota?

Operating and Maintenance Costs

- *Asset-Based Margins* – In what manner and to what extent should asset-based margins (profits from the sale of wholesale energy generated by utility facilities) be credited to ratepayers?

- *Non-Asset-Based Margins* – How should the costs of producing non-asset-based margins (profits from the sale of wholesale energy not generated by utility facilities but bought, marketed, and sold by utility personnel using utility business infrastructure) be determined and how should they be credited to ratepayers?

- *Ancillary Service Market Margins* – What portion of ancillary service market margins (profits from wholesale power generated to meet requirements for spinning reserves, regulation reserves, and supplemental reserves) should be credited to ratepayers?

- *Midwest Independent Transmission System Operator (MISO) Schedule 16 and 17 Costs* – Should the Company be permitted to recover deferred administrative costs (Schedule 16 and 17 costs), incurred as a result of its membership in MISO?
- *Financial Accounting Standard 106 (FAS 106) Transition Costs* – May the Company recover the amortized costs of complying with FAS 106 – the national accounting standard changing the accounting treatment of post-retirement, non-pension benefits (chiefly, health

insurance) – despite its failure to request Commission approval of amortization under the Commission order addressing implementation of the new accounting standard?

- *Line Loss Adjustment* – Should the Commission adjust the Company's claimed line losses or adjust the inter-state allocation of those line losses due to the Company's MISO participation, due to changes in the voltage level at which it serves Enbridge, or due to other factors?

- *Fuel Clause Adjustment Timing* – Does the fuel clause adjustment contain an uncorrected mismatch between costs and revenues that should be addressed in this rate case?

- *Fuel Cost Refinements* – Should the Company be required to refine its fuel cost procedures by adopting Key Performance Measures for fuel costs, by using the same fuel clause adjustment procedures in all three states in which it operates, or by amending its tariffs to explain how the Uniform System of Accounts treats fuel costs?

- *Cost Recovery in MISO Transactions* – Do Company accounting procedures adequately protect against double-recovery of the operating and maintenance costs associated with sales and purchases in the MISO wholesale market?

- *Pension and Other Benefit Costs* – What is the appropriate test year cost of employee pensions, health and dental insurance, and other employee benefits?

- *Economic Development Costs* – Is it just and reasonable to permit rate recovery of the Company's test year economic development costs?

- *Incentive Compensation* – Are the structure of the proposed incentive compensation program, the proposed incentive amounts, and the proposed accounting treatment reasonable and appropriate?

- *Charitable Contributions and Organizational Dues* – What portion of the Company's charitable contributions and organizational dues should be recovered in rates?

- *Demand-Side Management Rebate Costs* – To what extent should the costs of the Company's energy-efficiency appliance rebate programs be recovered in rates?

- *Renewable Energy Credits and Future Carbon Credits* – Should the Commission adopt a specific ratemaking treatment for these credits, which are either not yet in existence or not yet trading in a fully functional market? If so, what ratemaking treatment should it adopt?

Rate Base

- *Inventory of Supplies and Materials* – What are reasonable and prudent inventory levels of supplies and materials to include in rate base?

- *Fuel Stocks in Rate Base* – What are reasonable and prudent inventory levels of fuel stocks to include in rate base?

- *Amortization of Rate Case Expenses* – What is a just and reasonable amortization period for the Company's rate case expenses?

Capital Structure and Rate of Return

- *Capital Structure* – What capital structure should the Commission impute to Otter Tail for ratemaking purposes?

- *Rate of Return on Equity* – What is the appropriate return on common equity for this company at this point in time?

Rate Design

- *Class Revenue Apportionment* – How should responsibility for meeting the revenue requirement be distributed among the Company's customer classes?

- *Marginal Cost in Rate Design* – Should the Company be permitted to base its rate design largely on marginal cost or should it be required to factor in past and near-future embedded costs?

- *E8760 Allocator* – Should the Company be required to use or develop a cost allocation system based on the cost of serving each customer class during each of the 8,760 hours of the year?

- *Allocating Production Plant Costs Between Demand and Energy* – What portion of fixed production costs should be attributed to meeting demand and allocated to the capacity/demand component of rates and what portion attributed to providing energy and allocated to the energy component of rates?

- *Allocating the Costs of High-Voltage and Low-Voltage Transmission Lines Between Customer Classes* – Should the Company continue charging "rolled-in rates," which spread the cost of all transmission lines over all customer classes, or should it exempt very large customers who connect directly with high-voltage lines from any cost responsibility for lower-voltage lines?

- *Declining Block Rates* – At what points, if any, in Otter Tail's rate structure, are declining block rates just and reasonable?

- *Residential Customer Charge* – What is a just and reasonable level for the customer charge component of the Company's residential rate?

- *Time-of-Day and Standby Rates* – How should the Company's time-of-day and standby rates be structured, especially in terms of reflecting marginal costs and generating costs at different times of day?

III. Otter Tail's Objection and Motion to Strike

A. Objection to Material Updating RUD-OAG's Discounted Cash Flow Analysis

The Company objected to the RUD-OAG's inclusion, in its exceptions, of tables and discussion updating its discounted cash flow analysis in response to Company claims that failure to update might have impaired the analysis's reliability and credibility.

The Administrative Law Judge had earlier granted a similar motion, excluding this material from the RUD-OAG's reply brief on grounds that it contained factual information not timely filed and not subject to cross-examination. The Administrative Law Judge noted, however, that the Commission could choose to admit the material during the period for exceptions and oral argument.

The Commission will admit the tables and accompanying discussion. While it is rare to admit factual material after the close of the evidentiary hearing, it is appropriate under the unique circumstances here.

This material is an extension of earlier testimony that was timely filed and fully subject to cross-examination. It is consistent with the earlier testimony; it does not raise new issues or otherwise prejudice any party. It was filed in response to Company concerns that could not be allayed or fully addressed without it. Its impact is cumulative, not dispositive. Finally, the Commission is aware that the material has not been subject to cross-examination and will take that fact into account as it weighs this and every other evidentiary item in the case.

For all these reasons, the Commission will admit the tables and accompanying discussion as part of the RUD-OAG's exception filing.

B. Objection to Quotation from Interview Notes in Related Proceeding

The Company also objected to Mr. Drews's inclusion, in his exceptions, of a lengthy quotation from interview notes compiled by an initial investigator in an earlier Commission case investigating claims that the Company was engaging in questionable accounting practices.[3] Here the Commission concurs with the Company and will not admit the material.

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[3] *In the Matter of Otter Tail Power Company's Report on a Call to its Ethics Hotline,* Docket No. E-017/M-04-1751.

Unlike the RUD-OAG's tables and discussion addressed above, the interview notes are not an extension of earlier testimony that was timely filed and fully subject to cross-examination. Nor were they submitted in response to Company claims that their absence rendered admitted testimony unreliable. Nor would their impact be merely cumulative; they would introduce and highlight issues that have been absent from or peripheral to this case, without giving the Company adequate opportunity to respond.

Further, the interview notes apparently come from the record of the earlier investigatory case and were never offered as evidence in this case, despite a Commission order clarifying that evidence from the earlier case would not be considered in this one unless duly admitted by the Administrative Law Judge.[4] It would require a compelling reason to revisit that earlier decision, which was made after full briefing by all parties and careful deliberation by the Commission.

For all these reasons, the Commission will grant the Company's motion to exclude from Mr. Drews's exceptions the lengthy quotation from the interview notes of the investigator in docket E-017/M-04-1751.

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held seven days of evidentiary hearings and two days of public hearings. He reviewed the testimony of 20 witnesses, dozens of exhibits, and over 1,000 pages of transcript. He made 492 findings of fact, 26 conclusions of law, and recommendations on all contested issues based on those findings and conclusions.

Having examined the record itself and having considered the report of the Administrative Law Judge, the Commission concurs in most of his findings and conclusions. On a few issues, however, the Commission reaches different conclusions, as delineated and explained below. On all other issues, the Commission accepts, adopts, and incorporates his findings, conclusions, and recommendations.

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[4] *Id*., Order Denying Reconsideration and Clarifying Earlier Order (January 17, 2008).

V. Corporate Cost Allocations

A. Introduction

1. Historical Background

In late 1994 and early 1995, the Commission completed a four-year, industry-wide proceeding to develop cost allocation principles to guide Minnesota utilities in apportioning costs between their regulated and unregulated operations. At the end of that proceeding the Commission adopted fully allocated cost accounting principles, based on the hierarchical costing principles the Federal Communications Commission had developed for use in telecommunications regulation.[5]

In brief, these principles are as follows:[6]

1. Tariffed rates shall be used to value tariffed services provided to the unregulated activity.

2. Costs shall be directly assigned to either regulated or unregulated activities whenever possible.

3. Costs which cannot be directly assigned are common costs which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.

4. When neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and unregulated activities, excluding the cost of fuel, gas, purchased power, and the cost of purchased goods sold.

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[5] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994); Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket (March 1, 1995); Order Clarifying Commission Order Dated September 28, 1994 (March 7, 1995).

[6] *Id.*, September 28, 1994 Order, p. 4, p. 6.

The Commission ordered all gas and electric utilities to be prepared to demonstrate their compliance with these principles in all future rate cases, unless they could demonstrate that (a) their unregulated activities were insignificant; (b) their alternative cost allocation principles produced results similar to those produced by using the approved allocation principles; or (c) the public interest would be better served by using alternative allocation principles.[7]

The Commission acknowledged that differences between utilities might justify differences in their cost allocation approaches, and it explained the showing required to support an alternative approach:

> The Commission understands that utilities differ in many essential respects, including their participation in affiliated operations. The Commission believes that the hierarchical principles offer sufficient flexibility for each utility to develop appropriate allocation methodologies based on the principles.
>
> Should a utility wish to base its cost separations on different principles, the burden of proof would be on that utility to prove that its cost allocation principles arrive at fully allocated costs, free of any cross-subsidization. The utility would have to show that the goals of fully allocated costing, as expressed in this and other Orders, are fully realized. The utility would have the burden of demonstrating that it has considered <u>all</u> of its costs and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations.[8]

2. The Company's Filing

In this rate case the Company demonstrated compliance with the first three of the four Commission-approved cost allocation principles listed above. Instead of complying with the fourth principle, however, which specifies a formula for determining a general allocator for all costs whose causes cannot be traced, the Company proposed a different formula.

The Commission's formula is the ratio between all expenses directly assigned or attributed to regulated activities and all expenses directly assigned or attributed to unregulated activities – excluding, in this context, the categories of fuel, gas, purchased power, and the cost of purchased goods sold. The Company's proposed formula is the ratio between the total revenues, assets, and labor dollars of its regulated utility and the total revenues, assets, and labor dollars of all its unregulated business entities.

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[7] *Id.*, March 1, 1995 Order, p. 1.

[8] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994) at 5.

The Commission-approved general allocator would allocate 28% of the general corporate costs for which causation cannot be determined to the regulated utility; the Company's proposed general allocator would allocate 38% of those costs to the utility. The dollar difference between the two general allocators is some $574,407 (total company) on an annual basis.

B. Positions of the Parties

The Company claimed that its alternative allocator was appropriate because it more accurately reflected the extreme diversity of its unregulated businesses and the capital-intensive nature of its regulated business. The Company also emphasized that the alternative allocator was nearly identical to the one approved for Xcel Energy in its last rate case.

The OES opposed the alternative allocator, mainly because it produced results very different from those produced by the approved allocator – a 38% cost allocation to regulated operations, as opposed to a 28% cost allocation to regulated operations. The agency argued that the alternative allocator failed the "similar results" and "public interest" tests set forth in the Commission's cost allocation orders.

The RUD-OAG opposed the alternative allocator, arguing that it had not been shown to more accurately match cost allocation with cost causation and that it distorted the impact of features unique to the utility business to increase cost allocations to regulated operations. The RUD-OAG also challenged the allocation of certain legal fees to regulated operations, challenged the way the Company had calculated the Commission-imposed cap on the incentive compensation allocated to regulated operations, and recommended convening a work group to examine Company cost-allocation practices in more detail.

C. Recommendation of the Administrative Law Judge

The ALJ found in favor of OTP's alternative allocator, mainly on the basis of four conclusions:

(1) The alternative allocator is reasonable and consistent with the principle that differences between the unregulated businesses at issue, as well as differences between the unregulated businesses and the utility, justify a different cost-allocation methodology.

(2) The alternative allocator is virtually identical to the one approved for Xcel Energy in that company's last rate case.

(3) The alternative allocator would allocate the same percentage of general *corporate* costs to the utility (38%) as the percentage of *common* costs allocated to the utility under the Commission-approved methodology, demonstrating reasonable results.

(4) The alternative allocator meets the standards set by Commission order for alternative allocation methodologies, i.e., it produces results similar to the results of the approved methodology or better serves the public interest.

D. Commission Action

The Commission respectfully disagrees with the conclusions of the Administrative Law Judge, which are examined individually below.

(1) The alternative allocator is reasonable and consistent with the principle that differences between the unregulated businesses at issue, as well as differences between the unregulated businesses and the utility, justify a different cost-allocation methodology.

These findings appear to be based on three Company claims: (1) that Otter Tail capitalizes a "substantial" portion of its labor costs, while the unregulated businesses capitalize "almost none" of their labor costs; (2) that the Company's unregulated businesses vary dramatically from one another, as well as from the regulated utility, in terms of revenues, assets, profit margins, labor intensities, and revenue/profit ratios; and (3) that the three-factor general allocator proposed by the Company would provide more stability than the Commission-approved general allocator.

These differences were thought to make it more equitable to base the general corporate allocator on the three factors of assets, labor dollars, and revenues, instead of on the Commission-mandated ratio between all costs directly assigned or attributed to regulated operations and all costs directly assigned or attributed to unregulated operations. (Again, "all costs," in this context, excludes fuel, gas, purchased power, and goods bought and sold.)

The Commission does not find these claims persuasive. First, the claim of a vast and significant disparity between the portion of labor costs capitalized by the utility and the portion of labor costs capitalized by the unregulated businesses is unsubstantiated. There is no hard evidence in the record to establish either the percentage or dollar amount of total labor costs capitalized by the utility or by the unregulated businesses.

The claim that capitalized labor costs significantly increase general corporate costs is similarly unsubstantiated. There is no evidence in the record showing the effects of the capitalization of labor costs on any of the business entities at issue, regulated or unregulated. Nor is there any evidence showing how capitalizing labor costs affects general corporate costs or translates into a need to reflect labor-cost capitalization in allocating general corporate costs between different business entities.

The same issues arise in regard to the claimed differences among the unregulated businesses, and between the unregulated businesses and the utility, in regard to revenues, assets, profit margins, labor intensities, and revenue/profit ratios. The record does not contain evidence detailing and documenting these differences, nor does it contain evidence detailing and documenting how and why these differences would translate into lower general corporate costs for the unregulated businesses. Neither does it contain evidence showing that operating such a large number and broad diversity of unregulated enterprises does not impose *higher* costs on Otter Tail than simply providing electric service in a monopoly environment, a notion with some intuitive credibility.

Further, the asset intensity and business diversity arguments ignore the fact that the Commission expected a wide diversity of unregulated businesses and fully understood the capital-intensive nature of the utility business when it adopted the cost allocation principles at issue.

Similarly, the record does not demonstrate that the alternative general allocator would be more successful in promoting stability than the Commission-approved general allocator, nor does it explain what stability means in the context of a figure like the general allocator, which is set in a rate case and remains stable until re-examined and potentially re-set in the next rate case

In short, the Company did not demonstrate by a fair preponderance of the evidence that the factors discussed above require the use of the three-part alternative general allocator to increase the accuracy with which costs are allocated to the business entity – regulated or unregulated – that is most likely to have caused them.

(2) The alternative allocator is virtually identical to the one approved for Xcel in that company's last rate case.

This claim is true. In Xcel's last general rate case,[9] the Commission permitted the Company to use an alternative general allocator nearly identical to the one proposed by Otter Tail in this case; the main difference was that Xcel's allocator factored in the number of full-time-equivalent employees instead of total labor dollars. The comparison is not relevant or probative, however, for two reasons.

First, Xcel's general allocator was not a contested issue in the rate case; the parties stipulated that the allocator was reasonable. It was therefore not expressly addressed by the ALJ or the Commission.[10]

Second, the parties to the rate case stipulated to the alternative allocator because Xcel's unregulated activities were insignificant.[11] Under the orders in the cost-allocation docket,

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[9] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-05-1428.

[10] *Id.*, ALJ's Report at ¶ 100.

[11] *Id.*, Direct Testimony of Nancy Campbell at page 7.

companies are not required to demonstrate compliance with Commission-approved cost-allocation principles if their unregulated activities are insignificant.[12]

For these reasons, Xcel's use of a similar alternative general allocator has no precedential or persuasive value in this case.

> (3) The alternative allocator would allocate the same percentage of *corporate* costs to the utility (38%) as the percentage of *common* costs allocated to the utility under the Commission-approved methodology, demonstrating reasonableness.

The cost-matching emphasis here is appropriate, but limiting the comparison to one set of costs, common costs, is not. The Commission-approved general allocator is based on a more comprehensive and broadly representative set of costs than just common costs; if it were not, the cost-allocations orders would have simply used common costs as the general allocator. Instead, they developed the much more inclusive formula of the ratio between all costs directly assigned or attributed to regulated operations and all costs directly assigned or attributed to unregulated operations.

Further, the Company has not demonstrated on the record that the common cost allocation figure of 38% more closely captures the origins of untraceable costs than, say, the management cost allocation figure of 30.5%, which is much closer to the Commission-approved general allocator of 28% than to the Company's alternative general allocator of 38%.

The Commission-approved general allocator was carefully developed based on many months of study and industry-wide participation. Its applicability to individual cases cannot be discredited on the basis of inexact, factually unsubstantiated comparisons.

> (4) The alternative allocator meets the standards set by Commission order for alternative allocation methodologies, i.e., it produces results similar to the results of the approved methodology or better serves the public interest.

The Commission respectfully disagrees and concludes that the proposed alternative general allocator fails both tests. It clearly does not produce results similar to the approved allocator, since it increases the costs allocated to the regulated utility by approximately one-third.

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[12] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994); Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket (March 1, 1995); Order Clarifying Commission Order Dated September 28, 1994 (March 7, 1995).

Neither does it better serve the public interest, a standard fleshed out in the original cost allocation order as follows:

> Should a utility wish to base its cost separations on different principles, the burden of proof would be on that utility to prove that its cost allocation principles arrive at fully allocated costs, free of any cross-subsidization. The utility would have to show that the goals of fully allocated costing, as expressed in this and other Orders, are fully realized. The utility would have the burden of demonstrating that it has considered <u>all</u> of its costs and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations.[13]

The Company clearly did not demonstrate by a fair preponderance of the evidence that its proposed general allocator would (a) arrive at fully allocated costs, free of any cross-subsidization; (b) fully realize the goal of fully allocated costing; and (c) equitably allocate burdens and benefits between regulated and unregulated operations, after due consideration of <u>all</u> of the Company's costs (emphasis in original).

The Company did not demonstrate by a fair preponderance of the evidence that its proposed alternative allocator would more accurately trace and allocate costs than the general allocator approved by the Commission; it has therefore failed to demonstrate that the alternative allocator would better serve the public interest.

For all these reasons, the Commission declines to adopt ALJ Finding 289 on corporate cost allocations and declines to adopt his recommendation that the Company be permitted to use its proposed alternative general allocator; rates will be set on the basis of the general allocator required under the Commission's cost-allocation orders. The Commission concurs with the remainder of the ALJ's findings on corporate cost allocation issues.

VI. Allocating the Costs of 41.6 kV and 69 kV Transmission Lines Between State Jurisdictions

A. Introduction

1. Historical Background

In July 2000, the Commission concluded a year-long proceeding to establish guidelines for classifying utility assets as transmission, distribution, or generation assets. The final order in that case (*Boundary Order*) adopted detailed guidelines for distinguishing transmission assets from distribution assets and directed that all Minnesota utilities use the guidelines in future proceedings

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[13] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994) at 5.

in which it was necessary to determine whether specific assets were transmission or distribution assets.[14]

The guidelines establish a 50 kV demarcation point -- lines at or under 50 kV are assumed to be distribution lines and lines over 50 kV are assumed to be transmission lines, unless application of a ten-factor test demonstrates that they should be classified otherwise. The ten-factor test is designed to determine how the lines actually function, and can be briefly summarized as follows:

(1) How does the seven-factor test developed by the Federal Energy Regulatory Commission for distinguishing transmission from distribution apply, and what is its outcome?

(2) Was the facility installed to serve a single customer?

(3) Does the facility serve wholesale or other grouped load either in a looped or radial configuration?

(4) Was the facility designed to serve single-phase load?

(5) Was the facility jointly planned with other utilities and are there contractual relationships controlling its use?

(6) What are the anticipated future uses of the facility, and will it be looped in the future?

(7) Does the facility interconnect two or more utilities?

(8) Who operates the facility and performs maintenance and repair, on a normal and contingent basis?

(9) What design and maintenance requirements does the facility meet under the National Electric Safety Code?

(10) What is the dominant functionality of the facility?

[14] *In the Matter of a Proceeding to Develop Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions*, Docket No. E-999/CI-99-1261, Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets (July 26, 2000).

2. The Company's Filing

Besides classifying its 230 kV and 115 kV lines as transmission assets, Otter Tail's filing classified some 3,900 miles of 41.6 kV lines and 200 miles of 69 kV lines as transmission assets. In accordance with standard regulatory practice and earlier Commission orders, the Company allocated transmission line costs between its North Dakota, South Dakota, and Minnesota service areas on the basis of each state's peak electrical demand and allocated distribution line costs to the states in which the lines are located.

Since the Company's Minnesota demand is as high as its North Dakota and South Dakota demand combined, slightly over half of the Company's transmission costs were allocated to its Minnesota customers.

B. Positions of the Parties

1. Otter Tail

The Company stated that it relied more heavily than other Minnesota utilities on low-voltage transmission lines because large portions of its service area are not densely populated, making 41.6 kV and 69 kV lines an economical and efficient alternative to the higher-voltage lines more commonly associated with transmission.

The Company's initial testimony analyzed the function of its 41.6 kV and 69 kV lines under the *Boundary* Order on a system-wide basis. In response to criticism by the Minnesota Chamber of Commerce, the Company conducted a segment-by-segment analysis of its transmission system, which it submitted into evidence shortly before the beginning of evidentiary hearings. This supplementary analysis resulted in the Company reclassifying 117 miles of line (2% of the total) as distribution, together with related substation equipment. This adjustment reduced the Company's overall revenue requirement by $7,200.

2. Chamber of Commerce and Enbridge

The Chamber of Commerce and Enbridge analyzed Otter Tail's 41.6 kV and 69 kV lines under the Commission's *Boundary Order* and contended that the Company had not rebutted the presumption that the lines were distribution lines, in part because the segment-specific study was not introduced in initial testimony.

They asked the Commission to classify the Company's 41.6 kV and 69 kV lines as distribution lines and to allocate their costs on the basis of location and mileage. This recommendation would reduce the overall annual revenue requirement by some $4.44 million.

3. The OES

The OES did not view the *Boundary Order* as determinative. The agency argued that the Company's 41.6 kV lines, despite performing a transmission function, provided primarily local benefits and that their costs should be allocated to the state in which they were located.

The OES compared the relationship between these "sub-transmission" lines and higher-voltage transmission lines to the relationship between highways and byways, with highways being properly funded by a larger pool of cost-causers than local byways.

This proposed adjustment would reduce rate base by some $13,725,672 and expense by approximately $1,322,467.

C. The Administrative Law Judge's Recommendation

The Administrative Law Judge examined the 41.6 kV and 69 kV lines under the Commission's *Boundary Order* and found that the Company had rebutted the presumption that these lines were distribution assets and had established that they were transmission assets.

He rejected the OES's proposal to allocate the costs of the 41.6 kV lines on the basis of their location, finding that the Company operated its transmission system as an integrated unit and that the location of individual components did not necessarily correlate with cost causation.

D. Commission Action

1. Comprehensive Findings and Conclusion Adopted

The Administrative Law Judge conducted a comprehensive and thorough examination of the status of the Company's 41.6 kV and 69 kV lines under the Commission's *Boundary Order*. He analyzed the record evidence as applied to each of the 20 factors[15] outlined in the order and concluded that the lines were transmission lines.

He carefully analyzed the OES's arguments in favor of establishing a new "sub-transmission" functional category for cost allocation purposes and the claim that lines under 50 kV provide mainly local benefits and should be paid for locally. He concluded that these proposals lacked factual and evidentiary support and that record evidence demonstrated the system-wide benefits of the Company's 41.6 kV lines. He therefore recommended allocating their costs between state jurisdictions on the basis of demand.

[15] The ten-factor test set forth in the *Boundary Order* contains multiple sub-factors.

The Commission has carefully reviewed the record and the arguments of the parties and concurs with the Administrative Law Judge on these issues; it accepts, incorporates, and adopts Findings 12 through 87 and Conclusion 20.

These findings and the resulting conclusion are straightforward, clear, and complete. They are supported by substantial evidence. Their underlying reasoning is compelling. They reflect accepted regulatory practice and sound public policy. The Commission accepts and adopts them for the reasons set forth in the Administrative Law Judge's Report.

2. Conflicting Secondary Findings Not Adopted

While the Commission concurs with the Administrative Law Judge's comprehensive and well-reasoned findings and conclusions on allocating the costs of the Company's 41.6 kV and 69 kV lines, the Commission does not accept or adopt isolated Finding 401 and accompanying Conclusion 21, which appear to conflict with those findings without explanation, supporting reasoning, or evidentiary support.

3. Fully Developed *Boundary Order* Study Required

While the record in this case fully supports the comprehensive findings of the Administrative Law Judge on allocating the costs of 41.6 kV and 69 kV transmission lines, the Commission will require the Company to file a fully developed study of its transmission system under the *Boundary Order* for examination in its next rate case. If no rate case is filed within the next five years, the Commission will require a filing to be examined on a stand-alone basis.

The Company is planning to add substantial amounts of generation and transmission to its system within the next few years. These changes, combined with the ongoing evolution of technology, state energy policy, and the regulatory landscape, may affect the Company's transmission operations. It is important to have a detailed, segment-by-segment understanding of how that system operates to ensure that the principles and guidelines set forth in the *Boundary Order* continue to be properly applied.

VII. E8760 Allocator in Allocating Costs Between State Jurisdictions

A. Introduction

Otter Tail allocated energy costs for both interstate cost allocation purposes and inter-class cost allocation purposes on the basis of kWh sales.

Xcel Energy and Minnesota Power have developed, for rate design purposes, an E8760 allocator, which allocates energy costs on an hourly usage basis, with adjustments by customer class weighting factors to reflect differences in class load patterns and hourly marginal energy cost. Neither utility has used the E8760 allocator for interstate cost allocation purposes.

B. Positions of the Parties

1. Enbridge and the Chamber of Commerce

Enbridge and the Minnesota Chamber of Commerce advocated requiring Otter Tail to use an E8760 allocator for both interstate and interclass cost allocations. Enbridge developed a "hybrid" E8760 allocator on the basis of Enbridge-specific and Minnesota-specific information and urged its use for both inter-class and interstate cost allocation.

2. The OES

The OES recommended requiring Otter Tail to develop an E8760 allocator for use in its next rate case in the context of intrastate rate design only. The agency stated that Enbridge's allocator was not based on enough information for use in this rate case.

3. Otter Tail

The Company stated that it had examined the possibility of developing an E8760 allocator, but had determined that it would not be cost-effective given the utility's size, load shape, and operational characteristics. The Company argued that Enbridge's proposed allocator was based on information that was much too limited to support a valid E8760 allocator.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Enbridge's proposed E8760 allocator did not have the factual support necessary to support its use. He concurred with Otter Tail that it was far from clear that the benefits of developing the allocator would justify the considerable costs involved. He recommended that the Company continue studying the costs and benefits of developing the allocator and that any allocator eventually developed be limited to use in rate design.

D. Commission Action

The Commission accepts, adopts, and incorporates the findings and conclusions of the Administrative Law Judge on this issue.

The E8760 allocator is a sophisticated tool that can make fine distinctions on cost-causation with significant accuracy, but developing the allocator requires compiling and analyzing large amounts of customer-specific and utility-specific data at great cost, especially on a system-wide, interstate basis. It is not clear that the benefits of having an inter-jurisdictional E8760 allocator would exceed the costs of developing it.

The Commission will therefore direct the Company to continue its investigation of the issue, but concurs with the Administrative Law Judge that it is unlikely that the allocator would be cost-justified and useful in any context other than intrastate rate design.

VIII. Asset-Based Margins

Changes in industry practices can warrant changes in regulatory practices. Providers of retail utility services have long engaged in auxiliary businesses. For example, utilities can generate and sell electricity to non-retail customers by employing the same plant, staff, fuel and long-term power contracts that the utility acquired to serve its retail customers. A utility can profit from buying and selling electricity generated elsewhere by employing the same energy-trading staff and resources that the utility acquired to serve its retail customers.

Shortly, a utility will be able to profit by selling spare capacity for the purpose of maintaining system reliability. And someday a utility may be able to profit by buying and selling permits to emit carbon, or buying and selling credits for having generated electricity from renewable sources.

These auxiliary businesses trigger concerns about how the related costs and benefits should be allocated to retail customers.

A. Introduction

The difference between the cost and the revenues arising from using utility assets to generate and sell excess electricity to non-retail customers is called the "asset-based wholesale margin." In 1986 the Commission set Otter Tail's rates on the assumption that $739,000 of Otter Tail's cost of serving retail customers each year would be offset by Otter Tail's asset-based wholesale margin.

These margins have grown since then. In 2002 the Midwest Independent Transmission System Operator, Inc. (MISO) established uniform terms for wholesale energy transactions, and in 2005 MISO initiated its "Day 2" market facilitating wholesale energy transactions. The change in Otter Tail's asset-based margins are set forth below:

Year	Asset-based Margins	Allocation to Retail
2002	$2.376 million	$739,000
2003	$4.339 million	$739,000
2004	$4.292 million	$739,000
2005	$5.953 million	$739,000
2006	$5.745 million	$739,000
2007	$5.658 million	$739,000

At the start of the MISO wholesale market, however, the Commission directed Otter Tail to revisit its allocation of wholesale margins no later than its next rate case[16] – that is, this current case.

Because ratepayers bear the cost of providing this wholesale energy, all parties agree that Otter Tail should allocate 100% of its asset-based wholesale margins to offset the cost of serving retail customers. The parties disagree, however, about the best mechanism to achieve this end.

B. Positions of the Parties

MCC proposes that all costs and benefits arising from asset-based wholesale transactions flow to retail customers via Otter Tail's fuel clause adjustment (FCA). While most parts of a utility's rates remain static between rate cases, a utility may adjust its rates monthly to reflect changes in the utility's cost of fuel and related matters.[17] In contrast, OES, Otter Tail and RUD-OAG recommend estimating the annual amount of asset-based wholesale margins that Otter Tail would generate and incorporating this figure into the calculation of Otter Tail's base (non-fluctuating) rates.

OES estimates the annual amount of asset-based wholesale margins to be $5.197 million. OES derives this figure from the average of the asset-based wholesale margins Otter Tail has generated over the past five years. OES has used a five-year average as the basis for estimating many aspects of Otter Tail's operations in this rate case.

Otter Tail estimates the annual amount of asset-based wholesale margin to be $5.009 million. Otter Tail derives this figure from the average of the asset-based wholesale margins it has generated since 2002, but excluding margins from 2002 (the first year of MISO's operations) and 2005 (the first year of MISO's Day 2 market operations) because they were lower and higher, respectively, than the margins earned in the other years. Otter Tail acknowledges that it has earned larger margins since the Day 2 market began in 2005, but notes that its margins have been trending back toward pre-Day 2 levels since then.

RUD-OAG estimates the annual amount of asset-based wholesale margin to be $5.745 million. This is the margin Otter Tail generated in 2006, which is the median level of margin Otter Tail has earned since the Day 2 market began operations. According to RUD-OAG, data regarding Otter Tail's margins prior to the start of the Day 2 market are not representative of Otter Tail's margins since the market began. In addition to imputing this level of revenues to rate base, in any year in which Otter Tail generates more than a $5.745 million margin RUD-OAG proposes that the Commission allocate the surplus to ratepayers via the fuel clause.

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[16] *In the Matter of Otter Tail Power Company's Petition for Approval of Revision to Rider for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Day 2*, Docket No. E-017/M-05-284, Order Establishing Accounting Treatment for MISO Day 2 Costs (December, 20 2006).

[17] Minn. Stat. § 216B.16, subd. 7; Minn. Rules, pt. 7825.2390 - .2920.

The parties' positions are represented by the following table:

Year	Asset-based Margins	MCC's position	OES's position	Otter Tail's position	OAG-RUD's position
2002	$2.376 million	-----			
2003	$4.339 million	-----	$4.339 million	$4.339 million	
2004	$4.292 million	-----	$4.292 million	$4.292 million	
2005	$5.953 million	-----	$5.953 million		
2006	$5.745 million	-----	$5.745 million	$5.745 million	$5.745 million
2007	$5.658 million	-----	$5.658 million	$5.658 million	
Party's proposal:		100% into FCA	$5.197 million into base rates	$5.009 million into base rates	$5.745 million into base rates, any surplus into FCA

C. Recommendation of the Administrative Law Judge

The ALJ favors treating asset-based wholesale margins much like other forms of revenue – that is, projecting an annualized level of revenue and incorporating that figure into base rates. Consequently the ALJ disfavored MCC's proposal.

Similarly, the ALJ disfavored RUD-OAG's hybrid proposal, noting that it would place Otter Tail's profits at risk in years in which Otter Tail did not generate the full $5.745 million margin, but would not give Otter Tail any offsetting relief in years when Otter Tail's margin exceeded $5.745 million.

In contrast, the ALJ found merit in estimating Otter Tail's margins on the basis of an average of its prior margins. As between OES's and Otter Tail's proposals, the ALJ found the latter to be more reasonable because it excluded both the extreme high and the extreme low data points before taking the average.

D. Commission Action

The Commission finds much merit in the ALJ's analysis. Consideration of additional factors, however, ultimately leads the Commission to calculate a different estimate of Otter Tail's future asset-based wholesale margins.

The practice of eliminating "outlier" data points may improve the reliability of estimates based on averages assuming all data points are otherwise equally probative. Here, it is unclear that this assumption is warranted. One of the points Otter Tail eliminates comes from the period before the start of the Day 2 markets – a regulatory era that has ended – and one comes from afterward – the regulatory period the Commission hopes to model. Thus, these data points are not equally probative of the issue at hand. In opposing the exclusion of the 2005 data, OES remarked that "if any years were excluded from the calculation, it would be more appropriate to exclude the data [from] the time before the start of the MISO Day 2 market."[18] The Commission is not persuaded that any estimate of Otter Tail's future margins in the Day 2 market will be improved by disregarding one of the only three data points from the Day 2 era.

At the same time, the Commission acknowledges Otter Tail's concern that its margins in the early years of the Day 2 market have been regressing toward pre-Day 2 levels, and may prove to be unrepresentative.

Faced with this uncertainty, the Commission will select an intermediate course. The Commission will estimate Otter Tail's future asset-based wholesale margins based on an average of the margins Otter Tail has earned over the past four years. This average will incorporate all of Otter Tail's experience in the Day 2 market as well as one year of Otter Tail's experience prior to the emergence of that market. In practice, the Commission's decision is similar to the OES's, but places less reliance on pre-Day 2 data.

In sum, the Commission will set Otter Tail's base rates on the assumption that Otter Tail's costs are offset by $5.41 million in revenues from Otter Tail's asset-based wholesale margins.

IX. Non-Asset-Based Margins

A. Introduction

As noted above, a utility can profit from buying and selling electricity generated elsewhere by employing the same energy-trading staff and resources that the utility acquired to serve its retail customers. While these transactions do not impose the same burdens on a utility's resources as asset-based wholesale transactions, all parties recognize that ratepayers should receive *some* portion of the benefit.

Parties reached consensus about many other aspects of this issue as well. Because the margins from these transactions are highly variable, all parties proposed that the fuel clause adjustment (FCA) provides an appropriately flexible mechanism for flowing these benefits back to ratepayers. The parties proposed, consistent with a recent rate case for Northern States Power Company d/b/a Xcel Energy,[19] that ratepayers should be shielded from bearing the cost if the utility loses money

[18] Campbell Surrebuttal at 12.

[19] *In the Matter of the Application of Northern States Power Company d/b/a Xcel energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-05-1428, Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation
(September 1, 2006); see also Tr. V. 5 at 54-55.

in its non-asset-based wholesale transactions. And whatever mechanism is selected for allocating the benefits, the parties proposed to let that mechanism take effect with the beginning of interim rates in this case, thereby increasing the amount of any refund of interim rates.

The parties disagreed, however, about the amount of the non-asset-based margins to allocate to ratepayers, and the amount of related costs. In the past Otter Tail allocated its costs of conducting non-asset-based wholesale transactions between its regulated and unregulated operations; during the test year this process allocated $993,173 to Otter Tail's unregulated operations. In approving new rates for Xcel Energy, however, the Commission allocated 25% of Xcel Energy's non-asset-based margins to ratepayers.[20]

B. Positions of the Parties

Otter Tail proposed to allocate $993,173 of non-asset based wholesale costs and 10% of the margins to ratepayers. Otter Tail reasoned that this allocation would be simpler than attempting to calculate and exclude the incremental costs and revenues of its non-asset-based wholesale operations.

OES supported Otter Tail's proposal to allocate 10% of the non-asset-based margins to ratepayers, but opposed the reallocation of non-asset-based costs to ratepayers. OES observes that 10% of the margins is much less than the $993,173 in costs that Otter Tail proposes to re-allocate.

RUD-OAG proposed allocating 25% of margins to ratepayers, consistent with the practice in the Xcel Energy rate case. Alternatively, RUD-OAG supported OES's proposal.

MCC estimated the cost of Otter Tail's non-asset-based wholesale operations and concluded that Otter Tail would need to allocate 30% of its margins in order to fairly compensate ratepayers.

C. Recommendation of the Administrative Law Judge

The ALJ found Otter Tail's proposal reasonable.

The ALJ acknowledged that a 10% share of the margin may seem small compared to the 25% that Xcel Energy allocates to its ratepayers. However, the ALJ noted that Otter Tail's non-asset operations are a much larger portion of its total operations, with the consequence that 10% of Otter Tail's non-asset margins represents a much larger figure for each Otter Tail customer than Xcel's 25% represents for each Xcel customer.

The ALJ found MCC's calculation of the cost of Otter Tail's non-asset-based wholesale operations to be unreliable due to inaccuracies, unsubstantiated assumptions, and inadequate allocations among Otter Tail's jurisdictions.

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[20] *Id.*

Finally, the ALJ concludes that OES's proposal would have the effect of crediting 48% of margins to ratepayers. The ALJ quotes Otter Tail as follows:

> [OES]'s approach .... would reduce, if not remove entirely, OTP's reasons for engaging in this highly risky enterprise. If OTP ceases this activity, its costs are not expected to decrease materially and certainly would not decrease by an amount equal to 10 percent of the anticipated margins. As recognized in the approved Xcel Energy settlement, utilities are not required to engage in this unregulated business.[21]

D. Commission Action

Based on the analysis provided by the ALJ and Otter Tail, the Commission is persuaded of the merits of allocating 10% of Otter Tail's non-asset-based wholesale margins to offset the cost of serving ratepayers, as reflected in the FCA, beginning with the implementation of interim rates. However, the Commission is not persuaded that this allocation also warrants re-allocating $993,173 in costs that were heretofore attributed to Otter Tail's non-asset-based wholesale operations.

The ALJ found persuasive Otter Tail's argument that, unless the $993,173 costs are allocated away from its non-asset-based wholesale operations, Otter Tail might abandon those operations altogether, resulting in ratepayers losing revenues from margins without avoiding very much cost. In other words, Otter Tail argues that the benefits arising from 10% of its non-asset-based wholesale margins exceed the incremental cost of its non-asset-based operations. But the only incremental cost analysis in the record – offered by MCC – does not support this conclusion. While Otter Tail and the ALJ criticized this analysis as flawed, no substitute calculation is provided.

Otter Tail bears the burden of proof in this proceeding and "[a]ny doubt as to reasonableness should be resolved in favor of the consumer." Minn. Stat. § 216B.03. In the absence of a reliable incremental cost study supporting Otter Tail's contentions, the Commission will continue to rely on the existing cost allocations. The costs allocated to Otter Tail's non-asset-based wholesale operations will continue to be allocated to those operations, not to ratepayers.

X. Ancillary Service Market Margins

A. Introduction

On September 9, 2008, MISO proposes to initiate a "Day 3 market" for "ancillary services" – services required to maintain system reliability and permit retail and wholesale operations to

[21] Ex. 10, Brause Rebuttal at 6-8.

proceed.[22] All parties agreed that some portion of Otter Tail's ancillary services margins should be used to offset ratepayer costs flowing through the fuel clause, but they disagreed about the appropriate amount.

B. Positions of the Parties

Because ratepayers would bear 100% of the cost of the assets and fuel used to provide Day 3 services, RUD-OAG argued that 100% of Otter Tail's ancillary services margins should be used to offset ratepayer cost.

In contrast, Otter Tail, OES and MCC proposed allocating 80% of any margins Otter Tail recovers in the Day 3 market to offset ratepayer costs, although they agreed that no party should be precluded from seeking a different allocation in a future proceeding. Moreover, Otter Tail stated its willingness to reconsider this allocation after it has gained more experience with the Day 3 market.

C. Recommendation of the Administrative Law Judge

The ALJ recommended allocating 80% of Otter Tail's ancillary services margins to offset ratepayer costs. Noting that Otter Tail has no obligation to enter the market, the ALJ reasoned that the opportunity to retain 20% of the margins it can generate would provide an appropriate incentive to participate. The ALJ recommended directing Otter Tail to begin this allocation within 60 days of the start of the Day 3 market.

D. Commission Action

Given the limited information available, the Commission finds merit in the ALJ's reasoning and recommendation, and will adopt them. Accordingly the Commission will direct Otter Tail, no later than 60 days after Otter Tail begins receiving revenues from the Day 3 market, to allocate 80% of its ancillary services margins to offset Otter Tail's cost of providing regulated services. Finally, the Company has stated its willingness to revisit this issue as necessary as the Day 3 market develops.

XI. MISO Schedule 16 and 17 Costs

A. Introduction

As discussed above, in 2005 MISO initiated its "Day 2" energy market. Member utilities such as Otter Tail began placing "bids" to buy the electricity they needed the next day to serve their customers, and began making "offers" of plants available the next day to generate electricity. These procedures enable MISO to identify the least-expensive generators to serve customer

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[22] See, for example, *In the Matter of Interstate Power and Light Company, Minnesota Power, Xcel Energy and Otter Tail Power Accounting Revision to Riders for FCA to Recover Costs and Revenues Related to MISO*, Docket No. E001,015,002,107/M-08-528.

demands, consistent with functional system constraints, with the goal of promoting efficiency. These procedures, however, also left doubts about how the various related costs should be allocated and recovered.

Ultimately the Commission concluded that most MISO costs could be allocated and recovered in much the same way as fuel-related costs had been recovered before the MISO Day 2 market began. But the Commission found certain administrative costs – those recorded on Schedules 16 and 17 – to be so distinct from other fuel-related costs as to preclude recovery through the fuel clause. Instead, the Commission authorized the utilities to defer these costs and seek their recovery in their next rate cases.[23]

B. Positions of the Parties

Otter Tail asked the Commission to authorize recovery of $323,239 in ongoing Schedule 16 and 17 costs, as well as $292,895 reflecting an amortized share of past Schedule 16 and 17 costs. In sum, Otter Tail argued that these costs are offset by the benefits of the MISO Day 2 market – benefits which Otter Tail estimates at more than $12 million. In particular, Otter Tail argued that its wholesale earnings in the Day 2 market permitted it to refrain from filing an earlier rate case; in this manner, ratepayers have profited from the Day 2 market, including its administrative costs.

OES agreed that the benefits of the MISO Day 2 markets outweigh the administrative costs *now*, but argued that Otter Tail has provided insufficient evidence that the past administrative costs were justified. As discussed in the context of Otter Tail's wholesale margins, Otter Tail's wholesale earnings have greatly increased since the start of the Day 2 market. This coincided with the rise of costs for administering that market. OES argued that ratepayers have borne an inappropriate share of Schedule 16 and 17 costs while receiving an inadequate share of Otter Tail's wholesale margins. The claim that Otter Tail's wholesale revenues have permitted Otter Tail to delay filing a rate case, thereby benefitting ratepayers, OES regarded as too speculative to credit.

C. Recommendation of the Administrative Law Judge

Accepting OES's argument – that Otter Tail must demonstrate that it has shared the benefits of its Day 2 wholesale transactions from 2005 through 2007 in order to justify recovery of its Schedule 16 and 17 costs for that period – the ALJ nevertheless found that Otter Tail is justified in recovering its costs.

It is uncontested, as noted in the discussion of Otter Tail's wholesale margins, that the Commission set Otter Tail's past rates assuming that some portion of Otter Tail's wholesale

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[23] *In the Matter of Otter Tail Power Company's Petition for Approval of Revision to Rider for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Day 2*, Docket No. E-017/M-05-284, Order Establishing Accounting Treatment for MISO Day 2 Costs (December, 20 2006).

margins would offset its other costs. Moreover, based on the entire record of these proceedings, the ALJ has found merit in Otter Tail's request to increase revenues, and the ALJ found no evidence that Otter Tail's financial circumstances changed abruptly prior to the test year. Consequently the ALJ found merit in the argument that wholesale revenues have enabled Otter Tail to delay seeking higher rates, and ratepayers have benefitted from this as well.

D. Commission Action

The Commission finds merit in the ALJ's findings and recommendation and will adopt them. Since its inception ratepayers have reaped benefits from the Day 2 market, and consequently from its administration, sufficient to offset its costs.

The Commission does not find OES's contrary arguments persuasive. In brief, OES alleges that during the initial phases of the Day 2 market, ratepayers bore greater costs while Otter Tail reaped greater rewards from wholesale transactions. What OES does not allege is any fault with the amount of Schedule 16 and 17 costs that Otter Tail incurred during these initial phases. In concluding that the benefits of the Day 2 market justify granting recovery of Otter Tail's *current* and *future* Day 2 administrative costs, OES largely supports Otter Tail's choice to join MISO and participate in the Day 2 market. But if Otter Tail (and other firms) had refrained from incurring those earlier administrative costs, there would be no Day 2 market today providing benefits to ratepayers.

The Commission authorized Otter Tail and other utilities to defer recovery of Day 2 administrative costs because the Commission recognized that these costs might prove to be prudent expenditures, but were nevertheless insufficiently related to fuel costs to warrant recovery through the fuel clause.[24] The Commission did not authorize this deferral to create a vehicle to adjust the wholesale margin allocations established in Otter Tail's last rate case.

As discussed above, all parties agree that Otter Tail's wholesale margin allocations warrant readjustment. Those adjustments take effect in the context of Otter Tail's interim rates, and will influence the calculation of any ratepayer refund. With these changes, ratepayers are assured of receiving a fair benefit from Otter Tail's wholesale transactions now and in the future. But the amount of Otter Tail's wholesale margins in the past are not directly relevant to allocating its deferred Schedule 16 and 17 costs in this case.

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[24] Docket No. E-017/M-05-284, Order Establishing Accounting Treatment for MISO Day 2 Costs, *supra*.

XII. FAS 106 Transition Costs

A. Introduction

In 1985 the Financial Accounting Standards Board (FASB) established that private firms should account for the cost of employee pensions through accrual – that is, they should record the pension debt as it is incurred, not merely as it is paid.[25] In 1990 FASB issued Statement of Financial Accounting Standards No. 106 (FAS 106), generally extending this policy to other post-retirement benefits (OPEBs). While firms could elect to recognize their accrued liability for such benefits immediately, the Standard also provides for firms to spread this recognition over a period of up to 20 years.[26]

In 1992 this Commission adopted FAS 106 accrual accounting for ratemaking purposes, subject to Commission review of the benefits programs and calculations for prudence and reasonableness.[27] The Commission expressed concern, however, that this accounting change might cause all Minnesota utilities to request a rate increase immediately and simultaneously in order to fully recover their FAS 106 transition costs. To avoid this outcome, the Commission agreed to permit each utility that sought rate relief within three years to recover all the transition costs it incurred between the beginning of FAS 106 and the implementation of new rates.[28] In discussing implementation of this new accounting procedure, the Commission concluded:

> The treatment of the transition obligation, including the proper amortization period assigned, and the propriety of funding the OPEB obligation will be decided in each rate case, on a case by case basis.[29]

While Otter Tail had nearly $15 million in FAS 106 transition costs, Otter Tail did not file a rate case or request deferred accounting at that time. Nor did Otter Tail record this entire expense as

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[25] Statement of Financial Accounting Standards No. 87.

[26] FAS 106, ¶¶ 254, 434 (December 1990). The Commission has not limited amortizations to 20 years, however. *In the Matter of the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106*, Docket No. U-999/CI-92-96, Order Denying Petition for Reconsideration, Granting in Part and Denying in Part Petitions for Clarification (November 2, 1992) at 3-4.

[27] Docket No. U-999/CI-92-96, Order Adopting Accounting Standard and Allowing Deferred Accounting (September 22, 1992).

[28] *Id.*; see also Order Denying Petition for Reconsideration, Granting in Part and Denying in Part Petitions for Clarification, *supra*, at 6.

[29] *Id.*, Order Adopting Accounting Standard and Allowing Deferred Accounting, *supra*, at 6.

an operating cost in 1992. Instead, Otter Tail elected to expense one twentieth of this amount each year for twenty years, or roughly $748,200 per year,[30] as provided by the FASB. As of December 31, 2006, $4,414,000 remained to be expensed. In the current case Otter Tail asked to recover $748,200 annually – including $373,629 from Minnesota ratepayers – to cover its FAS 106 transition costs.

B. Positions of the Parties

Because Otter Tail declined to file a rate case seeking to recover these costs by January 1, 1996, as envisioned in the Commission's Order adopting FAS 106, OES argued that Otter Tail elected to forgo rate recovery of FAS 106 transition costs. OES read the Commission's Order to reflect the conclusion that utilities that do not need rate relief within the first three years of FAS 106 demonstrate that they have sufficient revenues. More generally, OES argued that it is inappropriate to cause current ratepayers to bear the cost of an adjustment that occurred 15 years ago. Therefore OES recommended excluding the $373,629 from Otter Tail's revenue requirement, and excluding all FAS 106 transition costs from Otter Tail's rate base.

Otter Tail argued that OES misconstrues the Commission's orders. According to Otter Tail, the Commission granted each utility the opportunity to recover its full FAS 106 transition cost if the utility filed a rate case by January 1, 1996. A utility that filed its rate case later would lose the opportunity to recover its full costs dating back to the beginning of FAS 106, but would not thereby forgo the opportunity to recover the amount of the cost being amortized in the rate case's test year.

Moreover, Otter Tail argued that OES's efforts to protect ratepayers from bearing FAS 106 costs are counterproductive. Otter Tail agreed that if it is not entitled to amortize its FAS 106 transition costs, then it should remove $373,629 from its estimated revenue requirement in Minnesota. But Otter Tail argued that it should also reverse the corresponding deductions it has made to its FAS 106 transition balance, thereby increasing Minnesota's portion of Otter Tail's rate base by $5,429,751 and increasing its revenue requirement in Minnesota by roughly $823,300. This is not an outcome any party desires.

C. Recommendation of the Administrative Law Judge

The ALJ noted that the Commission specified that it would address FAS 106 matters on a case-by-case basis, and that Otter Tail had not previously filed a case in which these matters would be addressed. Because Otter Tail had failed to secure the necessary Commission approval to recover its FAS 106 transition costs within the initial three-year transition period, the ALJ concluded that Otter Tail was precluded from seeking recovery of those costs now.

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[30] Otter Tail amortized $881,000 per year in 1993, 1994 and 1995, and has amortized $748,200 per year thereafter.

D. Commission Action

The Commission has not previously addressed the extent to which a utility that declined to file a rate case during the Commission's three-year transition period would be able to recover FAS 106 transition costs. While the ALJ attempts to apply the language of the Commission's orders to these circumstances, those orders were simply not crafted for this purpose.

The Commission authorized three years of deferred accounting for FAS 106 transition costs in order permit utilities additional time in which to seek full recovery of these costs. In offering this regulatory accommodation, however, the Commission did not mean to withdraw the standard regulatory practice permitting recovery of test-year expenses, including amortized expenses.

As noted above, the Commission adopted FAS 106 accrual accounting for Minnesota utility ratemaking purposes subject to Commission review for prudence and reasonableness of the relevant benefit programs. Nothing in the Commission's Orders precludes a utility from demonstrating the merits and prudence of its benefits expenditures and seeking recovery of the transition amounts in rates, whether or not the utility filed a rate case during the Commission's three-year transition period.

That said, the Commission will decline to grant rate recovery of Otter Tail's FAS 106 transition costs at this time. While Otter Tail ably demonstrates that it is not legally precluded from seeking recovery of its FAS 106 transition costs, it neglected to provide support for the prudence and reasonableness of the underlying benefits programs and their costs. Such a showing is required both by statute and Commission Order.[31] In the absence of such showing, no rate recovery can be authorized.

XIII. Line Loss Adjustment

A. Introduction

The amount of electricity a utility generates is not the amount of electricity a utility sells; some amount of electric energy is dissipated in transmission. The magnitude of the loss depends on a number of factors; in particular, the higher the voltage, the lower the percentage of energy lost.

B. Positions of the Parties

Enbridge operates oil pipelines and represents roughly 20% of Otter Tail's load in Minnesota. Enbridge raised a number of concerns about the quality of data Otter Tail maintains regarding energy consumption and line losses. In particular, Enbridge alleged that Otter Tail's outdated line loss estimates systematically skew the allocators used to divide costs among Otter Tail's various state jurisdictions on the basis of the amount of energy consumed.

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[31] Minn. Stat. §§ 216B.03, 216B.16; Docket No. U-999/CI-92-96, Order Adopting Accounting Standard and Allowing Deferred Accounting, *supra*.

Enbridge noted that since Otter Tail's last rate case, MISO began operating the grid for electricity transmitted at 100 kV and higher and Enbridge purchased its transformer from Otter Tail. As a result, Enbridge now receives power at 115 kV, thereby producing reduced line losses, and receives this power via a MISO-operated transmission line, thereby relieving Otter Tail of responsibility for the line losses. By failing to calculate line loss estimates reflecting these new developments, Enbridge argued, Otter Tail has skewed the allocation of costs toward Minnesota.

On the basis of the best data Enbridge was able to obtain – principally data about its own energy consumption patterns – Enbridge proposed adjustments to the energy allocators, resulting in less cost being allocated for recovery from Minnesota ratepayers. While Enbridge did not deny the computational shortcomings of its proposed allocators, it argued that Otter Tail has failed to demonstrate the merits of its own allocators, despite bearing the burden to do so. Minn. Stat. § 216B.16, subd. 4. Moreover, Enbridge claimed that Otter Tail reneged on a promise to develop an E8760 allocator as part of this case and has otherwise failed to cooperate in Enbridge's efforts to rigorously develop alternative cost allocators.

Otter Tail opposed Enbridge's proposed changes to its inter-state energy allocators, arguing that Enbridge misapprehends the relevant facts. Otter Tail acknowledged estimating line losses for most customer classes at 8.1%, similar to the estimate it used in its prior rate case. But Otter Tail also developed lower line loss estimates for certain customer classes. For its pipeline group Otter Tail estimated line losses of 4.25%, down from more than 6% in its prior rate case, in recognition of changed circumstances.

Otter Tail acknowledged that MISO now bears the direct line loss cost of electricity transmitted on 115 kV lines, including the lines serving Enbridge. But Otter Tail now bears those costs indirectly as they are incorporated into MISO charges. Thus, Otter Tail continues to bear the costs related to line losses for serving the pipeline customer class, and must continue to recover those costs from the members of that class.

Otter Tail identified two principal shortcomings in Enbridge's use of line loss estimates to affect jurisdictional allocations. First, changes in line loss estimates in Minnesota would presumably also apply in North and South Dakota as well. The likely consequence of these changes is that the *proportion* of costs allocated to each jurisdiction would remain the same. Second, Enbridge's analyses are based largely on data regarding its own operations, without regard to the operations in the rest of Otter Tail's service area. Thus, even if Enbridge were justified in concluding that costs should be shifted away from its own operations, it is not clear that those costs would be shifted to another state's jurisdiction; they might be shifted to other Minnesota customers instead.

OES acknowledged that it also had questioned Otter Tail's energy loss data, but is satisfied that the allocators are adequate for purposes of the current case.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Otter Tail had adequately addressed the concerns raised by Enbridge, and consequently recommended approving the use of Otter Tail's line loss estimates.

D. Commission Action

The Commission agrees with the ALJ and will decline Enbridge's proposed adjustments. The Commission cannot determine on the basis of the evidence before it that Enbridge's proposal would result in better estimates of line losses. Moreover, the Commission is persuaded that any adjustment to line loss estimates, when applied equally in each jurisdiction, is likely to leave total jurisdictional allocations largely unchanged.

The Commission is concerned about any allegation of parties failing to cooperate in the process of discovery or litigation. However, the presiding Administrative Law Judge is typically in the best position to address these matters, and such matter should be raised during evidentiary proceedings. This Commission will not attempt to adjudicate such concerns at this late stage of the process.

The Commission will, however, require the Company to develop a new energy loss study for filing with its next general rate case.

XIV. Fuel Clause Adjustment Timing

A. Introduction

Generally a regulated utility may not change its rates without completing a rate case in which all costs and revenues are considered. As an exception to that general principle, however, the Commission authorizes energy utilities to adjust rates monthly to reflect changes in the cost of energy.[32] This adjustment occurs via the "fuel clause adjustment" (FCA).

The price of a kilowatt-hour (kWh) has two components: a "base rate" charge which incorporates a historical level of energy cost per kWh, and an adjustment which reflects the extent to which the cost of energy per kWh changed relative to the level embedded in base rates. In the case of Otter Tail, this cost of energy is measured on the basis of average energy costs in the second and third month prior to the adjustment period. For example, the size of any adjustment paid in February is based on the difference between the amount of energy costs embedded in base rates and the average energy costs the utility incurred during the preceding November and December.

In addition, to the extent that Otter Tail over- or under-collects energy revenues in any given year, Otter Tail calculates an adjustment that is implemented beginning July 1 of each year. The adjustment is equal to the amount of aggregate over- or under-recovery for the prior year divided by the total number of kilowatt-hours projected to be sold within the jurisdiction.

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[32] Minn. Rules, pt. 7825.2390 - 7825.2920.

Enbridge alleged that Otter Tail's test year costs reflect the cost for fuel used prior to the test year that was being recovered within the test year. Otter Tail and OES dispute this allegation.

B. Positions of the Parties

Enbridge alleged that, in the transition between old and new rates, the cost of energy used in the last few months prior to the test year were incorporated into the test year via the FCA mechanism. Enbridge proposed an adjustment – calculated based on the difference between the Otter Tail's old and new base cost of energy – to remove this amount from the test year revenue requirement. Enbridge argues that this has been the Commission's practice since Minnesota Power's last rate case,[33] and is provided for in Otter Tail's own statement of Revenue Recognition Accounting Policies in its annual report to shareholders.

Otter Tail denied that costs recovered through the fuel clause are for energy consumed in a prior period. Otter Tail claimed that Enbridge's adjustment was based on manipulations of the base cost of energy for 2006 – an irrelevant figure for purposes of Enbridge's concern about lags. Otter Tail demonstrated how a revenue-neutral reduction in base rates (and corresponding increase in the FCA) would alter the amount of adjustment calculated by Enbridge's formula.

Far from being standard practice in Minnesota, Otter Tail could find no evidence that the Commission had ever discussed the need for such a lag adjustment. Nor was Otter Tail persuaded that Enbridge's allocator was required by its own internal policies; rather, the language in its annual report merely disclosed that Otter Tail offered a FCA mechanism.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Otter Tail had adequately addressed the concerns raised by Enbridge. Moreover, because OTP has a true-up mechanism that operates outside of base rates, any under- or over-collection in 2006 has already been trued-up. Consequently the ALJ recommended that the Commission decline to adopt Enbridge's FCA lag adjustment.

D. Commission Action

Otter Tail argues that "the FCA rate for February 2007 is applied to February 2007 sales for the sole purpose of recovering February 2007 costs." Enbridge argues that, because the FCA in any given month is based on the cost of energy in two of the three prior months, the FCA is "recovering costs for a past period." This distinction is largely semantic. The purpose of the test year is to create an initial basis for evaluating a utility's operating costs and revenues. The Commission finds no systemic bias in considering those costs and revenues without incorporating the FCA lag adjustment described here.

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[33] *In the Matter of the Application of Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E-015/GR-94-001, Findings of Fact, Conclusions of Law and Order (November 22, 1994).

That said, if Enbridge were concerned that the FCA was allowing the cost of energy in October, November and December of 2005 to have an undue influence on the price of a kilowatt during January, February and March of Test Year 2006, Enbridge was free to propose to substitute data from October, November and December of 2006. Enbridge did not.

Instead, Enbridge proposed calculating an adjustment based on differences in the amount of energy in the new and the old base rates. The relevance of base rates to Enbridge's concerns about FCA lags is unclear, given that they did not take effect until 11 months after the test year ended.[34]

Finding the ALJ's analysis persuasive, the Commission will adopt the ALJ's recommendation and decline to adopt Enbridge's FCA lag adjustment.

XV. Fuel Clause Refinements

A. Introduction

Parties raise a variety of issues related to fuel costs and fuel cost recovery:

- Should Otter Tail adopt another key performance indicator (KPI) related to fuel costs?
- Should Otter Tail strive to standardize the fuel clause language and procedures in all three state jurisdictions?
- Should Otter Tail conform the language of its fuel clause to the language of the Federal Energy Regulatory Commission's Uniform System of Accounts?

B. Positions of the Parties

Otter Tail establishes KPIs – a program of defined objectives and regular measurement – to focus individual and organizational attention on specific tasks of high importance. OES and MCC supported having Otter Tail establish a KPI for fuel management, noting the importance of managing this growing portion of Otter Tail's costs.

While Otter Tail is mindful of the need to manage energy costs, it argued that imposing a KPI specifically for that purpose would be redundant and counterproductive. Otter Tail explained that it already has established five principal KPIs, and subordinate KPIs to support the principal ones. Thus Otter Tail has a principal KPI for Generating Plant Availability with a subordinate KPI for fuel costs.

Otter Tail argued that this organization of KPIs makes the most sense for Otter Tail's system. Because Otter Tail has low-cost generators that are always in demand, Otter Tail's comparative advantage is in maximizing the number of hours that its generators are available to operate.

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[34] *In the Matter of Otter Tail Power Company's Petition for a Change in Base Cost of Energy*, Docket No. E-017/MR-07-1220, Order Setting New Base Cost of Energy (November 27, 2007) (new base rates effective November 30, 2007, upon the start of interim rates).

Strategies for acquiring fuel or contracting for power are designed with an eye to further this principal goal. In sum, Otter Tail argued that it already has a comprehensive system designed to focus staff resources optimally, and injecting a new KPI into this system could send conflicting signals to its staff and otherwise intrude upon management prerogative.

Otter Tail operates with a different fuel clause adjustment mechanism in each of its three jurisdictions. MCC argued that this lack of uniformity created needless complications for all concerned and created opportunities for Otter Tail to over-recover fuel costs. MCC proposed that the Commission direct Otter Tail to adopt uniform fuel clause adjustment mechanisms in all its jurisdictions. Otter Tail observed that there is as yet no evidence of any over-recovery and, in any event, each state exercises its own control over the terms of Otter Tail's fuel clause adjustment mechanism in the state.

Finally, MCC argued that the language of Otter Tail's fuel clause ("Energy Adjustment Rider") is needlessly confusing, and recommended some language that better conformed to the Uniform System of Accounts, especially Account No. 151 Fuel Costs.

C. Recommendation of the Administrative Law Judge

Without dismissing the merits of the ideas set forth above, the ALJ found insufficient reason in the record to recommend that the Commission order Otter Tail to implement them.

D. Commission Action

The Commission finds the ALJ's reasoning to be sound and will adopt it. While the Commission finds no fault with any of the proposals offered by OES or MCC, nothing in the record persuades the Commission of the need to force Otter Tail to implement these changes against its will.

The Commission acknowledges the growing importance of managing fuel costs. But it is the role of management to determine how best to respond to that importance. An incentive to focus employee attention on one objective is, ultimately, an incentive to take employee attention away from other objectives. Nothing in the record persuades the Commission of the need to inject itself into the management of Otter Tail's KPI system.

Whatever the merits of having uniform fuel adjustment clause language, the Commission is disinclined to order a utility to undertake modifications to its operations in three separate jurisdictions without a more developed record.

Finally, whether or not Otter Tail incorporates the appropriate language from the Uniform System of Accounts into its tariffs, that language governs its fuel clause transactions.[35]

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[35] Minn. Stat. § 216B.10, subd. 1 (prescribing Uniform System of Accounts for Minnesota utilities); see also Minn. Rules, part 7825.2400, subp. 8 (defining cost of fossil fuel, for purposes of fuel clause, as the current period withdrawals from Uniform System of Accounts

Otter Tail has as much interest as any party in managing its staff optimally and refining its tariff language; Otter Tail is therefore in the better position to determine whether and how to respond to the parties' proposals.

XVI. Cost Recovery in MISO Transactions

A. Introduction

As noted above, participants in the MISO Day 2 energy market can place bids to buy the electricity they need the next day, and can offer terms for using their generators to produce electricity. MISO then identifies the least-expensive generators to serve customer demands consistent with functional system constraints. Thus, when a MISO utility generates and delivers electricity to serve its own customers, the terms of MISO's tariff characterize this transaction as a "sale" of electricity into the Day 2 market (upon generation) and a "purchase" of the electricity back from the market (upon delivery). Reconciling traditional concepts of utility transactions with the sometimes counter-intuitive terms in MISO's tariff has posed a challenge since the start of Day 2 operations.

At issue here is how a traditional ratemaking expense – the cost of operating and maintaining (O&M) a generator – flows through to Otter Tail and its ratepayers when Otter Tail "purchases" electricity via the Day 2 market. OES and Otter Tail resolved their concerns regarding appropriate recovery of O&M costs when Otter Tail is serving its own customers (that is, when the amount of electricity Otter Tail sells into the market is at least equal to the amount it delivers to its customers at any point in time). But they disagreed about the appropriate recovery when Otter Tail purchases electricity from a third party (that is, when Otter Tail's customers are using more electricity than Otter Tail is selling into the market at any point in time).

B. Positions of the Parties

OES expressed concern that ratepayers are over-paying O&M costs when Otter Tail purchases electricity in the Day 2 market from a third party.

Otter Tail's retail customers pay both a base rate and a fuel clause adjustment. Via base rates, Otter Tail's customers pay Otter Tail's O&M costs, among other things. Through the FCA, rates are adjusted for net changes in Otter Tail's energy costs, including net changes in the amount Otter Tail spends to purchase electricity in the wholesale market. The cost of power in the wholesale market presumably reflects the cost of generation, including the cost of fuel, operation and maintenance. Thus when Otter Tail serves customers with electricity purchased from a third party, Otter Tail recovers the following:

- In base rates: various costs, including Otter Tail's O&M costs (even though its own plant did not operate to provide the electricity).

No. 151.)

- In the fuel clause: the cost of the power purchased from the third party to the extent it exceeds the cost of energy embedded in base rates – presumably including the cost of fuel, operation and maintenance.

Otter Tail reduces its fuel costs by not running its plant, and this savings flows through to ratepayers via the fuel clause. Arguably Otter Tail also reduces its O&M costs by not running its plant but, because those costs are embedded in base rates, ratepayers see no savings. As a consequence, ratepayers avoid the cost of paying for Otter Tail's fuel, but they continue to pay for Otter Tail's O&M while also paying for the third party generator's fuel and O&M.

Otter Tail denied that Day 2 market transactions permit it to double-recover O&M costs. Otter Tail argued as follows:

- OTP incorporates the cost of O&M into the price it demands when offering to sell electricity into the market. The margins Otter Tail earns on asset-based wholesale transactions are credited back to offset ratepayer costs, as discussed above.

- OTP removes the cost of O&M when it books the transaction to the FCA, thereby ensuring that Otter Tail only recovers its O&M costs via base rates.

- OTP pays market prices when it buys power from third parties. That market price may or may not reflect the third-party provider's O&M costs.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Otter Tail adequately addressed the concerns raised by OES. In the absence of evidence that Otter Tail double-recovers its O&M costs, the ALJ recommended making no adjustment for this issue.

D. Commission Action

The Commission concurs in the ALJ's conclusion. OES's concerns invite the Commission to scrutinize market transactions to determine which components are O&M costs and which are not. The current record is insufficient to permit such scrutiny.

The Day 2 market is designed to ensure that the lowest-cost generators are dispatched first, consistent with operational constraints. To the extent that Otter Tail serves its customers with electricity generated by another party, it does so because that electricity was the lowest-cost energy available. Ratepayers benefit from these low costs, whether or not they are deemed to reflect a generator's O&M costs.

Finding no ratepayer harm, the Commission will decline to make any adjustments to Otter Tail's cost of service with respect to this matter.

XVII. Pension and Other Benefit Costs

A. Introduction

Otter Tail proposed to recover test year costs of $19,277,539 for pensions, post-retirement benefits other than pensions (OPEBs), and medical/dental plan benefits. This figure was $414,984 *lower* than its actual costs in 2006, the test year, because the Company proposed to recognize known and measurable changes in these costs.

The Company used an actuarial firm to determine its test year costs for pensions and OPEBs; to determine its test year costs for medical and dental benefits, it used its actual 2007 costs from January through July, and projected costs for the remaining months of the year.

B. Positions of the Parties

Otter Tail defended its numbers as empirically sound and amply supported by record evidence.

The OES recommended reducing recoverable benefit costs to $17,664,141, based on a 5-year simple average of data for 2003 through 2007. The OES favored averaging over reliance on actuarial data for two main reasons: (1) it claimed that averaging more accurately approximates costs that fluctuate over time, since actuarial studies focus on specific time periods; and (2) the Commission required averaging of benefit costs in a 2003 rate case filed by Interstate Power and Light Company.[36]

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the OES did not challenge (a) any of the data underlying the Company's cost figures; (b) the data, methodology, or outcome of the actuarial studies; or (c) the qualifications of the firm that conducted the actuarial studies. He rejected the proposition that averaging is generally superior to actuarial studies and noted that the Commission has based benefit costs on actuarial studies in two recent, major rate cases.

The Administrative Law Judge concluded that the actuarial studies yielded more reliable cost figures than the five-year average recommended by the OES and recommended using the Company's cost figures to set new rates.

D. Commission Action

The Commission concurs with the Administrative Law Judge. The goal of ratemaking is to reflect actual costs as accurately as possible, and the actuarial studies in the record – as well as the actual and projected medical/dental costs for calendar year 2007 – are sound empirical evidence for what

[36] *In the Matter of a Petition by Interstate Power and Light Company for Authority to Increase Electric Rates in Minnesota*, Docket No. E-001/GR-03-767.

those costs are likely to be. Averaging can be a useful tool for estimating fluctuating costs, but if there is a more precise tool available at reasonable cost, it should be used. The actuarial studies in the record in this case are such a tool.

Further, the 2003 *Interstate* case offers very little guidance on the appropriate treatment of pension and other benefit costs in this rate case. Not only is the *Interstate* decision, like most Commission decisions, intensely fact-specific, but it did not even address the issue of averaging versus actuarial studies. Further, the Commission rejected averaging in favor of actuarial studies in a major rate case two years later,[37] and it explicitly rejected the claim that *Interstate* supported averaging over actuarial studies in another rate case the same year.[38] In short, using averaging to determine pension and benefit costs is not more consistent with standard or past regulatory practice than using actuarial studies.

For all these reasons, the Commission concurs with the Administrative Law Judge that the Company's proposed pension and benefit costs should be approved.

XVIII. Economic Development Costs

A. Introduction

The question posed is whether it is just and reasonable to permit rate recovery of the Company's test year economic development costs.

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[37] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-05-1428, Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation (September 1, 2006).

[38] *In the Matter of the Application of CenterPoint Energy Minnesota Gas, a Division of CenterPoint Energy Resources Corp., for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-05-1380, Findings of Fact, Conclusions of Law, and Order (November 7, 2006) at p. 18.

B. Positions of the Parties

Otter Tail requested that $330,000 in economic development expenses be included in revenue requirements, including $175,000 in labor costs, $20,000 in related expenses, a $35,000 loan pool loss provision, and a new $100,000 community matching-grant-component.[39] The Company justifies the $330,000 requested and the recovery of 100 percent of its expenses, asserting that the program is cost-effective. Otter Tail argued that its economic development program efforts help to stabilize its communities by reducing intra-territory migrations and out-migrations.

Otter Tail's economic development efforts in 2006 included some 44 projects throughout its Minnesota territory, involving a wide range of business categories. The Company credits these projects with saving numerous existing jobs and creating many more jobs in Minnesota.

The OES recommended that the Commission not allow the Company to recover any costs of economic development through its utility rates, arguing that the Company did not demonstrate that its economic development program is cost-effective with respect to out-migrations.

The RUD-OAG asserted that the Commission has historically allowed 50 percent of economic development costs to be included in revenue requirements, but questioned whether, in fact, utilities should be promoting economic development. The RUD-OAG asserted that economic development also benefits the Company's unregulated operations, which would justify a sharing of costs associated with economic development.

The RUD-OAG also argued that at a time when there are legislative and Commission efforts to reduce electric consumption, economic development programs that expand demand for electric power have the opposite effect, and are in conflict with legislative and regulatory mandates.

AG-Processing asserted that the Company's reliance on a 1992 Northern States Power Company electric rate case[40] for the proposition that it should recover 100 percent of its economic development costs is misplaced, arguing that the decision shows that the Commission did not award 100 percent cost recovery for all programs deemed cost effective, and in fact only awarded 50 percent of the economic development costs in that case.

AG-Processing also argued the Commission should not make ratepayers bear the full cost of the economic development program, and that at most, a 50 percent sharing of economic development costs with the Company's non-utility operations was appropriate. AG-Processing further asserted that both shareholders and the utility benefit from its economic development efforts. AG-

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[39] The Company has spent about $250,000 annually on economic development in the last five years in Minnesota.

[40] *In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-92-1185, Findings of Fact, Conclusions of Law and Order (September 29, 1993).

Processing finally argued that numerous other agencies are involved in economic development in the utility's service area and that to the extent those efforts - by cities, counties and state agencies – are funded with tax dollars, ratepayers pay twice, first through utility rates and then through taxes.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with Otter Tail that its economic development program is cost-effective and recommended 100 percent recovery, based mainly on a finding that the Commission has directed 100 percent rate recovery if a utility's economic development program is demonstrated to be cost effective.

D. Commission Action

The Commission respectfully disagrees with the recommendations and conclusion of the Administrative Law Judge to allow Otter Tail 100 percent of its costs for economic development. Upon review of the facts in this case, the Commission is not convinced that awarding 100 percent of Otter Tail's economic development expenses is appropriate or justified in this matter.

In Finding 345, the ALJ misperceives what he assumes to be a Commission directive with respect to this issue, in stating that 100 percent of a company's costs should be allowed if a utility's economic development program is demonstrated to be cost effective. The case on which Otter Tail relied for that proposition did not, in fact, authorize 100 percent recovery of economic development expenses, but 50 percent.[41] And more importantly, it discussed the possibility of an award of 100 percent only in passing; it did not require such an award if a utility proved that its economic development program was cost-effective:

> If a rigorous program-by-program cost-effectiveness analysis had been conducted, *it could be argued* that the company should recover 100% of its expenditures for programs which proved cost effective. . . .[42]

Nor is the Commission persuaded by the OES's argument that Otter Tail's proposed expenses must be entirely disallowed because the Company has not met its burden of proof, and that, accordingly, none of the economic development costs are justified. As this Commission has previously concluded, any link between economic development expenditures and benefits to ratepayers will of necessity be indirect. This indirect impact of necessity means that such costs are not easily translated into hard data analysis.

[41] *Id*. at 47.

[42] *Id*. at 47.

Minn. Stat. § 216B.16, subd. 13 permits, but does not require, the Commission to allow a utility to recover from ratepayers the expenses incurred in economic and community development.[43] Hence, the Commission's decision as to whether and in what amount to allow economic development recovery is discretionary.

The Commission recognizes that economic development programs in a utility's service area benefit Company shareholders, as well as ratepayers. Shareholders benefit in multiple ways from successful economic development programs. Their overall revenues are obviously higher and more stable when their service area is thriving, but they also sustain lower bad debt costs, face lower risks of stranded investment, and reap substantial public relations benefits within the communities they serve.

Further, the Company's unregulated businesses derive substantial benefit from any program that helps Otter Tail's utility business thrive – the utility business contributes 50 percent of the Company's pre-tax income and provides a level of financial strength and stability that is hard to duplicate outside the context of providing essential service in a monopoly environment.

For all these reasons, it is appropriate for shareholders to share in the cost of the Company's economic development programs. The Commission approves inclusion of 50 percent, or half, of Otter Tail's proposed economic development program expenses in test year expenses. This decreases test year expenses by $165,000.

XIX. Incentive Compensation

A. Introduction

The Company proposed to include in rates the cost of its employee incentive compensation program. It based test year costs on the annual average of incentive compensation paid over the last five years, subject to a cap of 25% of individual employees' salaries.

The OES pointed out specific errors in the Company's calculations, which the Company corrected. The Company also agreed to apply the 25% cap to incentive compensation paid to employees who conduct the purchase and sale of wholesale power, in response to OES concerns.

B. Positions of the Parties

The OES recommended that the Commission adjust incentive compensation costs to remove the effects of all asset-based margins and 10% of all non-asset-based margins, based on its understanding that these amounts had been included in the past earnings on which incentive compensation had been based and that their exclusion now would lead to over-recovery. The OES

[43] Minn. Stat. § 216B.16, subd. 13 states, "The Commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development."

also recommended establishing a mechanism by which the Company would refund to ratepayers any incentive compensation amounts not paid to Company employees.

The RUD-OAG initially recommended basing incentive compensation on 2006 actual levels, later joined in the OES's position, and did not take exception to the Administrative Law Judge's findings and recommendations on the issue, presumably leaving that issue to the OES.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company had demonstrated that the incentive compensation amounts sought were reasonable and should be included in rates. He also recommended requiring the Company to establish a mechanism to refund to ratepayers any incentive compensation amounts included in rates and not paid to employees.

D. Commission Action

The Commission accepts, adopts, and incorporates the Administrative Law Judge's careful analysis of this issue and accepts his recommendations.

No one challenged the soundness of the Company's incentive compensation plan, as revised in response to OES's comments, and no one suggested that the plan would result in excessive compensation to Company employees. The dispute turned on the effects of prospective changes in the accounting treatment of asset-based wholesale revenues. In the past, largely because of the long gap between this rate case and the last one, these revenues were not accurately factored in to the earnings on which the Company's revenue requirement had been set; in the future, they will be. This change will have no significant practical impact on earnings, however, because the revenues were consistently included in the earnings on which incentive compensation was calculated.

Therefore, both the dollar amount of incentive compensation included in rates (the annual average of actual incentive compensation payments made over the five years ending in the test year) and the formula used to determine incentive compensation are consistent with standing practice and current realities.

The Commission also concurs with the Administrative Law Judge that the Company should be required to establish a mechanism to refund to ratepayers any incentive compensation included in rates that is not actually paid. While it is probable that the Company will continue to make payments under the incentive compensation plan throughout the period that rates will be in effect, the terms of the plan do not require the Company to do so. In fact, the plan explicitly grants the Company the right to discontinue it at any time.

Under these circumstances, a tracking and refund mechanism is required, and the Commission will so order.

XX. Charitable Contributions and Organizational Dues

A. Introduction

The question posed is what portion of the Company's charitable contributions and organizational dues should be recovered in rates.

B. Positions of the Parties

Otter Tail proposed including in its revenue requirement $92,377 for charitable contributions, which reflects 50 percent of the Company's charitable contributions.[44] This amount reflects the Company's agreement with the OES that the amount it originally proposed for recovery ($141,334) should be adjusted down by $46,604 to arrive at a total of $92,377.

Otter Tail also proposed including $211,315 of organizational dues in its revenue requirement. The Company argued that the organizational dues included are consistent with the Commission's Order in its last rate case and with the Commission's Statement of Policy on Organizational Dues. The Company disagreed with the OES's recommendation to reduce membership fees paid to organizations not located in Minnesota.

The Company argued that organization dues are allocated to jurisdictions like most other expenses, and that it would be inappropriate to disallow payments for dues to organizations located outside Minnesota. Otter Tail claims that the organizational dues for North Dakota and South Dakota that were included on schedule G-3 were not in fact included in the test year.

The OES requested a $9,061 adjustment to the test year which would reduce the amount included in Otter Tail's revenue requirement for organizational dues to $202,254. As a basis for its request, the OES asserted that the list Otter Tail provided of all of the membership dues paid in 2006 included membership dues totaling $9,061 for some twenty organizations located in North Dakota and South Dakota. OES argued that if the Company does recover expenses for these twenty membership dues, it should be from North and South Dakota ratepayers, not Minnesota ratepayers.

AG Processing asserted that Otter Tail's electric customers should not bear the full share of costs for dues and contributions, as only 26 percent of the Company's revenue and only 45 percent of the profits for 2007 were from the utility. AG Processing argued that a portion of Otter Tail's charitable contributions and organizational dues should be allocated to its unregulated businesses and only the remainder should be included in the revenue requirement.

[44] Minn. Stat. § 216B.16, sub. 9 allows a utility to include a maximum of 50 percent of eligible charitable contributions as an operating expense.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission find that Otter Tail's charitable contributions are recoverable pursuant to Minn. Stat. § 216B.16, sub. 9 and that no adjustment should be made to the amount of charitable contributions and organizational dues included in the Company's proposed revenue requirement.

D. Commission Action

The Commission accepts and adopts the Administrative Law Judge's finding that Otter Tail has met its burden of proof to show that its charitable contributions are recoverable pursuant to Minn. Stat. § 216B.16, sub. 9. The Commission finds that the Company's charitable contributions are prudent.

The Commission, however, respectfully disagrees with the ALJ with respect to organizational dues, and accordingly will not adopt the portion of the ALJ's finding with respect to organizational dues.

First, the Commission required utilities in docket 90-1008 to first directly assign costs whenever possible, and then to allocate costs that cannot be directly assigned using a cost-causative allocation method. Therefore, membership dues paid to organizations located outside of Minnesota should be directly assigned to those jurisdictions.

Second, Otter Tail has offered no record evidence verifying that the $9,061 has been excluded from the test year. The Company's initial filing stated that the test year dues expense was $211,315, which is the total of all of the items listed in schedule G-3. The Company's claimed exclusion could not be verified. The record does not provide any detail as to what dues were included in the test year, because the cost was charged to various expense accounts. In light of the foregoing, the Commission will disallow $9,061 from Otter Tail's test year organizational membership dues, which will reduce the amount included in Otter Tail's revenue requirement for organizational dues to $202,254.

XXI. Demand-Side Management Rebate Costs

A. Introduction

The Company proposed to include in rates some $131,051 in expenses related to demand-side management programs providing rebates to customers participating in energy efficiency programs relating to thermal storage, water heaters, and dual fuel.

B. Positions of the Parties

The RUD-OAG and AG Processing opposed inclusion of these expenses because the Commission had disallowed rate recovery for similar programs in the Company's 1986 rate case. This disallowance had been based on concerns that the programs tended to shift, rather than reduce, usage and that they rewarded "free riders," customers who would make these changes even if the rebates were not offered.

The OES conducted a cost/benefit analysis of the programs, found them to be cost-effective with minor changes agreed to by the Company, and recommended rate recovery.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended including program costs in rates, finding the OES's cost/benefit analysis credible and persuasive.

D. Commission Action

The Commission concurs with the Administrative Law Judge.

Energy efficiency is a cornerstone of state energy policy. The testimony of the OES is clear, thorough, and persuasive. The programs, as modified in response to OES comments, are clearly cost-effective and further important state policy goals. Their cost is appropriately included in rates.

XXII. Renewable Energy Credits and Future Carbon Credits

A. Introduction

MCC asks the Commission to adopt in this proceeding a specific ratemaking treatment for these renewable energy credits and future carbon credits, which are either not yet in existence or not yet trading in a fully functioning market.

B. Positions of the Parties

Consistent with its position on margin sharing, MCC argued that Otter Tail should be required to share future carbon credits and renewable energy credits with ratepayers, as ratepayer assets and expenses will be used to generate them. MCC asserted that regardless of how the Company is required to account for current revenues from margin trading, any new sources, such as renewable energy credits and future carbon credits should be shared with ratepayers in the same proportion and through the fuel clause adjustment.

Otter Tail disagreed with the MCC, reasoning that the request is premature, as the Commission has only begun to address the trading of carbon credits and renewable energy credits and has to date declined to address the issue of cost recovery. Otter Tail asserted that until more is known about how these markets will be structured and how the Company might participate in them, it is not possible to develop a reasoned position on this issue. Finally, the Company asserted that this is an issue that should be addressed for all Minnesota utilities, not just Otter Tail.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that MCC's proposal not be adopted as a part of this proceeding.

D. Commission Action

The Commission accepts, adopts and incorporates the decision of the Administrative Law Judge on this issue. The Commission has not yet addressed the overarching issue of cost recovery for renewable energy credits and carbon credits, and it would be premature to do so in this proceeding.

XXIII. Inventory of Supplies and Materials

A. Introduction

The Company's inventory levels of supplies and equipment increased by 19% from January 1 to December 31, a change the Company attributed primarily to extensive damage from a severe ice storm in late November and early December, and secondarily, to increases in the cost of equipment and supplies.

B. Positions of the Parties

The RUD-OAG maintained that the Company had not been maintaining adequate levels of supplies and materials prior to the ice storm and should therefore be permitted to recover only a 10% increase in inventory levels of supplies and materials.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended permitting recovery of the full amount of supplies and materials, finding the increase reasonable in light of the damage inflicted by the ice storm, the need to replenish inventory supplies, and documented increases in equipment prices.

D. Commission Action

The Commission concurs with the Administrative Law Judge. He carefully evaluated the Company's testimony on pre- and post-storm supply levels and on increases in the prices of cable, transformers, and other essential equipment. He found no basis to attribute rising costs to mismanagement and found test-year inventory levels reasonable and representative of ongoing needs.

The Commission accepts and adopts the Administrative Law Judge's findings and conclusions and will permit rate recovery of these costs.

XXIV. Fuel Stocks in Rate Base

A. Introduction

The Company's fuel stock costs increased by 16% during the test year, a change the Company attributed to a need to replenish fuel stocks depleted by recurring rail delivery problems and an associated need to maintain fuel supplies adequate to ensure reliability.

B. Positions of the Parties

The RUD-OAG challenged the increase as unreasonable or due to an initial failure to maintain adequate fuel supplies. The RUD-OAG recommended limiting rate recovery to a 10% increase.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended permitting recovery of the full amount of fuel stock costs, finding the increase reasonable in light of evidence documenting disruptive delays in the delivery of coal to the Company's Big Stone and Hoot Lake plants and the need to maintain adequate supplies to ensure reliability.

D. Commission Action

The Commission concurs with the Administrative Law Judge. He carefully evaluated the Company's testimony on rail delivery problems and fuel supply levels and found it persuasive. He found, for instance, that at one point the Company had been forced to reduce the output of its Big Stone plant for a seven-week period to conserve coal.

He found no evidence of mismanagement and concluded that increasing fuel stock levels was a reasonable response to previous shortages. He found test-year fuel stock levels reasonable and representative of ongoing needs.

The Commission accepts and adopts the Administrative Law Judge's findings and conclusions and will permit rate recovery of these costs.

XXV. Amortization of Rate Case Expenses

A. Otter Tail's Proposal

Otter Tail estimated its rate case expenses at $1,495,000. The Company allocated 2.31 percent, or $34,521, to unregulated activities. Otter Tail proposed a three-year amortization period for rate case expenses. The cost included in the test year was $486,822, after making the OES's correction for the allocation to unregulated activities.[45]

The Company asserted that the OES's and RUD-OAG's recommended five-year amortization period was unreasonable, as it relied primarily on the premise that the simple average of years between the Company's rate cases – 6.4 years – should be the basis of the amortization period. Otter Tail argued that use of the OES's and RUD-OAG's simple historical average includes a substantial period of time – 1987 to 2007 – that is not representative of current and forward economic conditions, making that average inappropriate as a predictor of the future.

Further, the Company argued that it has begun a substantial capital investment program, which is estimated to involve approximately $759 million of investment over the next five years, with some $336 million relating to Big Stone II and $423 million relating to other projects.

Otter Tail stated that the unrepresentative 20 year period should be ignored, and the amortization period should be based on the more similar cycle of electric utility rate cases that preceded that gap, during which the average duration between the Company's rate cases was 2.75 years.

Finally, the Company noted the concerns raised by the OES and RUD-OAG regarding the potential for over-recovery of expenses were the Company not to file another rate case in the three-year amortization time period proposed. Otter Tail proposed that any additional revenues recovered be subject to deferred accounting, with any excess amounts recovered credited against the revenue requirement in the Company's next rate case.

B. The OES and the RUD-OAG

The OES did not challenge the Company's estimate of rate case costs and agreed with the proposed 2.3 percent allocation to the unregulated activities. While acknowledging that many things can affect a utility's need to file a rate case, the OES and the RUD-OAG recommended amortization over five years, asserting that it has been 20 years since Otter Tail filed its last rate case, and that the three-year period proposed by the Company was inappropriate. The RUD-OAG maintained that a five-year amortization period would help avoid the potential for over-recovery, if a rate case were not filed within three years. Finally, the RUD-OAG asserted that a shorter period would put ratepayers at risk of paying for costs that would not exist after the three-year amortization period has passed.

While continuing to recommend that the Commission establish a five-year amortization period, the OES conceded that there was some merit to the Company's deferred accounting proposal, noting that it would discourage the Company from filing a rate case sooner than three years by placing the risk of under-recovery on Otter Tail.

[45] The Company's acceptance of the OES's recommendation regarding allocation reduced the three-year amortization from $498,333 to $486,822.

The OES recommended that if the Commission accepts the Company's proposal, it should clarify that the Company should record to a deferred account $40,569 – the annual amortization of $486,822 – for each month that it has not filed a rate case after December 1, 2010.[46]

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Company that a three-year amortization period was reasonable. The ALJ also found that the Company's proposal to establish a deferral account for rate case expenses recovered beyond the three year period is a sound approach to avoid over-recovery from ratepayers.

D. Commission Action

The Commission accepts, adopts and incorporates the findings of the Administrative Law Judge and will set a three-year period for recovery of rate case expenses. The Commission also accepts the ALJ's recommendation with respect to Otter Tail's proposal to establish a deferral account, and orders that if the Company's next rate case occurs after having recovered its rate case expense, Otter Tail will defer further recovery of rate case expenses at a rate of $40,469 per month, and credit this amount to offset its revenue requirement in its next rate case.

XXVI. Cost of Capital Generally

The preceding portions of this Order address the calculation of some of Otter Tail's costs of operation. This portion will address the calculation of Otter Tail's cost to attract the investment necessary to finance Otter Tail's operations.

In setting just and reasonable rates, the Commission provides an opportunity for a prudently-managed utility to recover its costs and earn a return sufficient to enable the utility to continue to attract necessary capital.[47] To determine a utility's aggregate cost of attracting capital, the Commission must identify what types of capital are appropriate to the utility's operations, the cost of each type of capital, and the optimal mix of the various types to finance the utility's operations.

The task of determining Otter Tail's capital costs is complicated because the Commission cannot directly observe the types, amounts or costs of Otter Tail's capital. As noted above, Otter Tail Power is not a separate corporate entity, selling its own stocks and bonds; rather, Otter Tail Power is an operating division of a larger entity, Otter Tail Corporation. All parties agree that the

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[46] December 1, 2010 is three years after implementation of interim rates in this rate case.

[47] Minn. Stat. § 216B.16, subd. 6; *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Corporation's capital costs and capital structure differ from the costs and structure appropriate for a prudently managed electric utility.

XXVII. Cost of Capital – Common Equity

A. Introduction

Capital comes in the form of debt or equity. Firms pay debt holders (bondholders) a fixed sum on a fixed schedule, and pay equity holders (shareholders) out of their profits after all other expenses – including interest due to bondholders – have been paid.

Each form of capital has advantages and disadvantages. Equity financing does not impose the payment schedules of debt financing, but shareholders demand a higher average return to compensate them for the risk they bear of not being paid. Debt financing tends to be cheaper than equity financing, but the demands to make regular payments impose a greater threat to the utility's solvency and ability to pay dividends.

For purposes of the current rate case, the parties agreed to analyze Otter Tail's capital in terms of 1) short-term debt, 2) long-term debt, 3) preferred stock and 4) common stock. Moreover, the parties agreed that it would be appropriate to impute to Otter Tail a cost of 6.52% for short-term debt, 6.32% for long-term debt, and 4.75% for preferred stock. But the parties disagree about the cost of common equity to impute to Otter Tail.

To attract equity investment, Otter Tail must offer people an opportunity to earn a profit sufficient to induce them to forgo other possible uses for their funds. Consequently the Commission must analyze the returns being offered by other investment opportunities of comparable risk available in the market. This is a three-step process. First, the Commission must identify firms comparable to Otter Tail. Second, the Commission must analyze data from those firms according to appropriate models. Third, the Commission must consider how Otter Tail would recover the cost of selling ("floating") common equity.

B. Positions of the Parties

OES, Otter Tail and RUD-OAG each prepared lists of firms they regard as being comparable to Otter Tail for purposes of analyzing capital costs. While each party used its own criteria to select comparable firms, they found agreement regarding many firms:

	OES	Otter Tail	RUD-OAG
American Electric Power			X
Cleco Corporation			X
Dominion Resources	X		
DPL, Inc.			X
Edison International	X	X	
Empire District Electric	X	X	X
Entergy Corp.	X	X	
Idacorp	X		
Pinnacle West Capital	X	X	X
PNM Resources			X
Progress Energy	X	X	X
Southern Company			X
Westar Energy		X	X
Xcel Energy			X

OES, Otter Tail and RUD-OAG then analyzed the data regarding the returns being offered by the firms on their respective lists. Each party used the Discounted Cash Flow (DCF) model, upon which the Commission has traditionally relied, as well as other analytical techniques. The DCF model assumes that the price someone is willing to pay for a stock reflects the present value of the flow of future payments expected from dividends and from the stock's eventual sale price. By using published forecasts of a firm's growth, and assumptions that the growth will be reflected in future payments, analysts can determine the rate of return that would be required to justify the firm's current stock price. Computationally, the return must equal the expected dividend yield (that is, the amount of current dividends divided by stock price) plus the expected growth.

Each party derived its list of comparable firms and applied the DCF model in a different way. For example, OES identified comparable firms by searching a database to identify firms that shared characteristics with Otter Tail. OES then took these firms and standardized the list by eliminating firms that 1) had abnormal debt ratios or 2) had both abnormal price changes and earnings patterns.[48]

This process resulted in a list of seven firms which OES then analyzed using the DCF model. OES concluded that four of these firms had unrepresentative rates of growth. Regarding three firms with relatively high growth rates, OES altered the DCF model to project lower growth in later years. Regarding one firm with relatively low growth – IDACORP – OES eliminated it from the analysis. Finally, after adding a floatation adjustment, OES's analysis supported a return of equity between 9.90% and 11.85%; OES proposed that the Commission adopt the midpoint of 10.91%. OES also conducted other analyses, including use of the Capital Asset Pricing Model (CAPM) to corroborate the reasonableness of its proposal.

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[48] OES and Otter Tail each selected firms partially on the basis of their "beta coefficient" – that is, the degree to which their stock prices rise and fall in sync with the stock prices of all other firms in the market.

Otter Tail followed a similar process to identify a list of comparable firms, identified a list of firms similar to OES's, conducted its own DCF analysis and added its own flotation adjustment to generate estimates of return on equity ranging from 10.28% to 12.74%. Otter Tail proposed that the Commission adopt an 11.25% return on equity. Otter Tail also conducted corroborating analyses using the CAPM and also the outcomes of 42 other rate cases involving vertically-integrated utilities such as Otter Tail.

RUD-OAG identified 10 firms as being comparable to Otter Tail, but also provided an updated analysis eliminating one firm from the comparison group. RUD-OAG estimated dividend yields for both a 3-month and a 12-month period. RUD-OAG estimated the rate of growth per share by analyzing not merely earnings growth forecasts but also forecasts of growth in dividends and book value. While RUD-OAG calculated a flotation adjustment, it ultimately proposed that the Commission not adopt one in this case. RUD-OAG argued that Otter Tail had not sold any stock during the rate case's test year and had only vague plans for issuing stock in the future. Based on its analysis, RUD-OAG found support for a return on common equity between 9.19% and 10.19%, and proposed that the Commission approve an (updated) return of 9.73%.[49]

C. Recommendation of the Administrative Law Judge

The ALJ concluded that OES had presented the most compelling argument and therefore recommended adoption of a 10.91% rate of return on common equity.

The ALJ analyzed the comparison groups proposed by OES, Otter Tail and RUD-OAG. The ALJ concluded that the method RUD-OAG used to assemble its list of firms failed to test for relevant points of distinction between its firms and Otter Tail. In contrast, the ALJ found merit in the selection methods used by OES and Otter Tail, and ultimately found that OES's list provided the better match for Otter Tail's operations.

The ALJ also considered how each party analyzed its list of firms, especially through the application of the DCF model to estimate dividend yields and earnings growth, and whether the parties included a flotation cost adjustment. While the parties arrived at comparable estimates of dividend yield, they differed regarding estimates of growth in earnings per share, and whether to include a flotation adjustment. Again the ALJ found the greatest merit in the OES's analysis, noting with approval that the OES had appropriately adjusted its analysis to account for firms with growth rates that were unsustainably high.

Finally the ALJ approved of the OES's proposal to incorporate a flotation adjustment. The ALJ reasoned that flotation costs were an appropriate cost of raising capital, the Commission has previously authorized recovery of flotation costs even when a utility had not sold any stock during the rate case test year, and Otter Tail had identified impending needs for increased capital.[50]

[49] RUD-OAG Exceptions (June 17,2008) at 7.
[50] See, for example, Brause Direct at 9-10.

D. Commission Action

The ALJ's examination of this issue is carefully considered, closely reasoned, and based on an exhaustive evidentiary record. The ALJ gives appropriate attention to each step of the process, with special focus on the choices each party makes that had the greatest affect on their ultimate recommendations. In particular, the ALJ focuses on the initial step of selecting the group of firms from which later conclusions would be drawn.

The ALJ concluded that OES's selection process was most suited to finding appropriate comparison firms. OES tested a database of US firms to find all firms with the following characteristics:

- Being primarily in the business of providing electric utility service
- Deriving nearly all revenues from regulated utility service
- Operating in the United States
- Publically trading shares on stock exchanges
- Having a bond rating comparable to Otter Tail's
- Not facing retail competition for the provision of electricity
- Paying dividends

Analyzing the firms that have these qualities in common, OES then sought to standardize the list by eliminating firms with –

- debt ratios more than one standard deviation[51] from the group's average or
- both price changes and earning fluctuations more than one standard deviation from the group's average

The Commission shares the ALJ's assessment of the evidence in the record and approves of OES's analysis – with one exception.

OES provides substantial and uncontested support for the proposition that IDACORP is a comparable firm to Otter Tail in the same standing as any other firm in OES's comparison group. Ultimately OES elected to exclude IDACORP's DCF results from its computation because OES deemed the firm's DCF-required ROE rate excessively low. The Commission observes, however, that OES did not similarly exclude firms from its computation when it deemed their growth rates too high, despite higher growth rates' clear translation into higher ROEs. While the addition of this one firm will not produce a large change in the ultimate result, the Commission concludes that including IDACORP in the ROE computation would provide a more balanced analysis than excluding it.

[51] While the "average" depicts the expected value for a group of data points, a "standard deviation" depicts the degree of dispersion within the data. In normally distributed data, most data points fall within one standard deviation from the average, with only 16% of data points falling above one standard deviation and 16% falling below.

Incorporating IDACORP into OES's analysis produces a midpoint return-on-equity estimate of 10.43%. This figure is within the range of returns supported by both OES and Otter Tail, using both the DCF model and the CAPM. The Commission will adopt this figure for purposes of calculating Otter Tail's capital costs.

XXVIII. Cost of Capital – Capital Structure

A. Introduction

As noted above, the parties agreed to analyze Otter Tail's capital in terms of 1) short-term debt, 2) long-term debt, 3) preferred stock and 4) common stock. The parties also agreed that, for purposes of calculating Otter Tail's capital costs, it would be appropriate to assume that Otter Tail raises 4.1% of its capital by selling short-term debt, 3.6% of its capital by selling preferred stock, and the remaining 92.3% of its capital by selling a combination of long-term debt and common equity. But the parties disagree about the relative amounts of long-term debt and equity to impute to Otter Tail.

B. Positions of the Parties

OES proposes that the Commission assume that Otter Tail raises 50.0% of its capital by selling common equity and 42.3% from long-term debt. OES selected this figure after analyzing the average capital structures of its comparison group and the average capital structure of all utilities with Otter Tail's bond rating. A 50% share of common equity appears between these two averages, and is within a standard deviation of each figure.

Otter Tail asks the Commission to assume that Otter Tail raises 52.9% of its capital by selling common equity and raise 39.6% from long-term debt. Otter Tail derives this number from internal financial records attributing some portion of the debt and equity sold by Otter Tail Corporation to its Otter Tail Power division. Otter Tail offers three arguments to bolster its position. First, Otter Tail notes that some of the firms in its list of comparable firms have common equity ratios higher than 52.9%, and that a 52.9% equity share is "nearly within one standard deviation of [OES]'s comparison group average...."[52] Second, Otter Tail argues that maintaining a higher equity ratio will help Otter Tail offset the added financial risks arising from planned capital investments. Third, Otter Tail argues that higher equity ratios result in lower rates for long-term debt, as evidenced by the rates it derives from parent entity Otter Tail Corporation.

Based on an analysis of its own comparison group, RUD-OAG proposes that the Commission assume that Otter Tail raises 47.55% of its capital by selling common equity and 44.75% from long-term debt.

[52] Otter Tail Initial Brief at 71.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that the parties' consensus regarding the appropriate levels of short-term debt and preferred stock is reasonable and should be adopted. Furthermore, the ALJ recommended that the Commission adopt the OES's proposal to set Otter Tail's cost of capital assuming Otter Tail raises 50% of its capital by selling common equity and raises the balance through long-term debt.

D. Commission Action.

Because dollars are fungible, the Commission has no meaningful way to evaluate the amount of debt or equity that Otter Tail Corporation imputes to Otter Tail Power.

While Otter Tail proposed a capital structure with 52.9% equity, data from Otter Tail's own comparison group revealed only an average 50.3% equity financing, and a much higher portion of debt than Otter Tail proposes.[53] Otter Tail seeks to borrow support from the OES's comparison group, but must acknowledge that the 52.9% equity ratio is more than a standard deviation above the equity ratio supported by OES's analysis. Finally, while Otter Tail correctly notes that a higher equity ratio tends to reduce the cost of debt, Otter Tail fails to acknowledge the corresponding dynamic that lower debt costs support increasing the debt ratio. The Commission must weigh both of these dynamics in determining an optimal capital structure for a regulated utility.[54]

As noted above, the ALJ recommends adopting OES's proposal of 50% equity and 42.3% long-term debt. The Commission finds the ALJ's recommendation reasonable. OES's position is the most moderate of the three proposed, is the most developed in the record, and derives from an analysis of the comparison group that the ALJ found to be the most representative of Otter Tail's operations. Consequently the Commission will adopt OES's capital structure for purposes of calculating Otter Tail's capital costs.

XXIX. Cost of Capital – Conclusion

For the foregoing reasons, the Commission will set rates for Otter Tail based on an assumed cost of capital of 8.33%, based on the following analysis:

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[53] RBH-1, Schedule 7.

[54] See *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 726 (Minn. 1987) ("The equity investor's stake is made less secure as the company's debt rises, but the consumer ratepayer's burden is alleviated. It is these conflicting interests that the Commission is to reconcile.")

Type of Capital	Proportion of Total	Cost	Weighted Cost
Short-Term Debt	4.1%	6.52%	0.27%
Long-Term Debt	42.3%	6.32%	2.67%
Preferred Stock	3.6%	4.75%	0.17%
Common Stock Equity	50.0%	10.43%	5.22%
Total	**100.0%**		**8.33%**

XXX. Class Revenue Apportionment

A. Background

The next issues will address how Otter Tail should set its rates to secure adequate revenues to cover those costs and earn a reasonable return on investment. This process of "rate design" requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

The Commission considers many factors in setting rates, including the cost of providing service. The cost of serving one customer will differ from the cost of serving another. But because similar types of customers impose similar types of costs on a utility, utilities find it useful to group customers into classes for purpose of analysis. Utilities learn about how the cost of serving one class of customer differs from another by conducting a "class cost of service study" (CCOSS).[55]

The Commission requires utilities to file a CCOSS because the cost a utility incurs to provide service is one factor the Commission considers in determining how much each customer class should contribute to meeting the utility's revenue requirement, and how to recover each class's share of the revenue requirement from the members of the class. Other factors include, inter alia, economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and ability to bear, deflect or otherwise compensate for additional costs.

B. Positions of the Parties

Otter Tail apportioned its total revenue responsibilities among its rate classes based on its CCOSS and its rate design objectives, including the objective of maintaining reasonable rate continuity, mitigating rate shock, and encouraging the efficient use of resources. OTP proposed the following allocation:

[55] Minn. Rules Part 7825.4300, subp. C requires a company filing a rate case where there is a material change in the rate structure to file a CCOSS.

Class Revenue Responsibility — Proposed increase by class					
			Proposed Increase by Class Responsibility		
Customer Class			Amount of Increase (as originally proposed)	Percent Increase	Percent Increase With FCA Adjustment
Residential			$4,522,094	12.50%	9.10%
Farms			286,159	13.25%	9.20%
General Service			1,538,033	5.88%	2.50%
Large General Service			6,081,942	10.50%	5.25%
Irrigation			40,461	14.00%	9.51%
Lighting			273,006	11.50%	9.16%
OPA			167,790	14.00%	9.15%
ControlIed Service Water Heating			215,284	15.00%	10.05%
ControlIed Service Interruptible			1,298,236	40.00%	31.80%
ControlIed Service Deferred			86,516	12.00%	6.03%

The RUD-OAG recommended a flat, across-all-classes rate increase, without any regard for Otter Tail's embedded CCOSS.

The MCC recommended a strict adherence to the CCOSS, without any regard for non-cost factors. MCC asserted that new conservation laws require residential revenue responsibility to be moved strictly toward costs.

The OES's analysis of the Company's rate structure concluded that significant subsidies currently exist between customer classes. OES proposed that a balancing of cost and non-cost factors should be used to determine revenue responsibility.

C. Recommendation of the Administrative Law Judge

The ALJ found that Otter Tail's proposed revenue apportionment minimizes the effect of rate shock, while modestly addressing subsidies between customer classes. The ALJ noted that the proposals of the other parties were problematic. OES's proposal reduced subsidies, but resulted in larger increases for some classes that could constitute rate shock. The RUD-OAG's proposal would mitigate rate shock, but did not address subsidies between customer classes. The ALJ found that of the various revenue allocation proposals, Otter Tail's best reflected and balanced the relevant cost and non-cost factors.

D. Commission Action

The Commission has carefully reviewed the record and the arguments of the parties and concurs with the Administrative Law Judge on this issue; it accepts, adopts, and incorporates Findings 402 through 411 and the first sentence of Conclusion 23 dealing with class revenue apportionment.

The Commission finds that a balancing of cost and non-cost factors justifies some movement toward cost for the residential class. The Company's class revenue responsibility proposal best balances a gradual move towards reducing subsidies for the residential class while mitigating rate shock for that class.

The ALJ's findings are straightforward, clear, and supported by substantial evidence. The Commission accepts and adopts them for the reasons set forth in the Administrative Law Judge's Report.

XXXI. Marginal Costs in Rate Design

A. Use of Marginal Costs vs. Embedded Costs in Rate Design

Otter Tail developed its rate design from the revenue requirements identified in its marginal cost of service study. MCC and Enbridge challenged the use of marginal cost instead of the embedded CCOSS to design rates,[56] and challenged how the Company's marginal capacity costs were developed.

B. Positions of the Parties

1. Enbridge and MCC

MCC asserted that Otter Tail should have used an embedded CCOSS to design rates, and challenged how the Company's marginal capacity costs were developed. MCC and Enbridge argued that the generation portion of Otter Tail's marginal cost study is focused on too short term a time period, and that the capacity costs of the Company's proposed future baseload additions, such as Big Stone II,[57] should be included in current demand charges.

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[56] Marginal costs describe the cost of producing the next unit of electricity; embedded costs are average costs.

[57] Big Stone II, a coal-fired power plant located in South Dakota, is Otter Tail's next planned baseload addition. On June 5, the Commission postponed a decision on the Company's application for a certificate of need for new power lines to carry the plant's energy into Minnesota.

Enbridge further asserted that Otter Tail's embedded CCOSS should have provided more information so that it could be used to check the marginal cost study. Enbridge argued that to make it possible to fairly evaluate changes proposed in its next rate case, Otter Tail should be required to submit an embedded CCOSS that provides sufficient unit cost information by function and rate class to make such evaluations.

2. Otter Tail

Otter Tail asserted that its marginal cost study reflects the marginal costs that will be incurred during the period the proposed rates are expected to be in effect. The Company asserts that its approach results in price signals that are as close as possible to the expected costs to supply additional kW and kWh while the rates are in effect.

Otter Tail further argued that reflecting the costs of future baseload additions such as Big Stone II in current charges is inappropriate, as it would base one rate component (demand charges) on the costs of future capacity additions, and the other component (energy charges) on current marginal costs.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that Otter Tail's use of a marginal cost study to design rates should be accepted, as well as the Company's use of market prices as the basis for marginal capacity costs. The ALJ found that the Company's proposed rates should not be altered to reflect anticipated capacity costs for the proposed Big Stone II plant.

D. Commission Action

The Commission concurs in the ALJ recommendation, and will accept Otter Tail's marginal cost study. The record supports the use of marginal cost to design rates and Otter Tail's marginal cost methodology. The evidence in this case supports the ALJ's finding that rates set at marginal cost provide efficient price signals to customers, promoting the educated use of resources.

The Commission also accepts Otter Tail's use of market prices as the basis for its marginal capacity costs. The Company's rates should not be altered to reflect anticipated capacity costs, such as those associated with the proposed Big Stone II facility.

Finally, despite its acceptance of the Company's marginal cost study in this matter, the Commission will also adopt Enbridge's suggestion to require Otter Tail to submit an embedded cost study, in addition to a marginal cost study in its next rate petition.

Traditionally, utilities have filed embedded cost studies. Commission Rules, however, do not specify what form of cost study must be utilized in a rate case. And the Commission has, in the past, recognized that "an increasingly competitive environment compels much closer attention to the economic efficiency issues only marginal cost studies can illuminate," and required a

Minnesota utility to file both a fully distributed embedded cost study as well a marginal cost study.[58] The Commission will so require in Otter Tail's next rate case.

XXXII. E8760 Allocator in Rate Design

A. Introduction

An E8760 allocator, discussed previously with respect to allocation of jurisdictional costs, is also an issue with respect to the CCOSS. It is an issue, however, with implications only for Otter Tail's next rate case, as no party has developed an E8760 allocator for use in this rate case.

As the name reflects, there are 8760 hours in the year, and the different energy costs in each hour would be used to develop a different energy factor for each customer class. The issue here is whether Otter Tail should be required to implement the E8760 allocator for CCOSS purposes in its next rate case.

B. Positions of the Parties

1. Otter Tail

Otter Tail proposed studying the implementation of an E8760 factor for use in its CCOSS, presenting the results of such a study, and possibly implementing an E8760 allocator for use in its CCOSS in its next rate case. Otter Tail proposed a step-by-step approach because of the large amount of study and work involved in developing an E8760 factor. Otter Tail indicated that its existing load research wasn't designed for the development of an E8760 factor, and that an evaluative process would involve placing new metering and collecting data for a specified time; testing samples; and potentially placing new load research meters.

2. OES

The OES recommended that Otter Tail be required to use the E8760 allocator in its next rate case for CCOSS purposes, because the allocator more accurately reflects costs for customer classes. The OES allowed that the data for such an allocator does not currently exist.

3. MCC

MCC also asserted that the E8760 allocator would be useful for class allocation purposes.

[58] *See, e.g. In the Matter of the Application of Minnegasco, a Division of NorAm Energy Corp., for Authority to Increase Its Natural Gas Rates in Minnesota*, Docket No. G-008/GR-95-700, Findings of Fact, Conclusions of Law, and Order (June 10, 1996) at 49.

C. Recommendation of the ALJ

The ALJ recommended that Otter Tail not be required to develop an E8760 allocator for its next rate case. Instead, consistent with Otter Tail's position, the ALJ recommended that the Company should be required to continue investigating whether the costs and benefits of an E8760 allocator justify development of such a methodology. Finally, the ALJ recommended that if the Commission does require the Company to develop such methodology, that it should be limited to CCOSS development purposes.

D. Commission Action

The Commission agrees with the OES, and with the ALJ's alternative recommendation, that Otter Tail should be required to use the E8760 allocator in its next rate case for CCOSS development purposes. The Commission has previously recognized that there is value in use of the E8760 allocator for purposes of a CCOSS, in adopting it as an allocator in Xcel Energy's most recent electric rate case.[59] In that case, the Commission recognized that "the choice of allocators does not, by itself, set rates; it merely establishes a tool for measuring costs," and found that the E8760 allocator produces a more accurate calculation of class costs than the E20 allocator.[60]

XXXIII. Allocating Costs of High-Voltage and Low-Voltage Transmission Lines Between Customer Classes

A. Introduction

For purposes of rate design, the issue posed is whether the Company should continue charging "rolled in rates," which spread the cost of all transmission over all customer classes, or exempt very large customers who connect directly with high-voltage lines from any cost responsibility for lower-voltage lines.

B. Positions of the Parties

Otter Tail asserted that the rolled in rate, which does not distinguish between high and low voltage, should be utilized. The Company argued that the identical issue was decided by the Federal Energy Regulatory Commission in 1980, in connection with the Company having been required by the U.S. Supreme Court to provide transmission services to the municipality of Elbow Lake, Minnesota. The issue arose whether Elbow Lake should only pay for the lower cost 41.6 kV facilities used to serve it, or whether it should be required to pay a rolled in rate that included the cost of higher voltage facilities. Noting that Otter Tail operated an integrated system, FERC found that a rolled in rate should apply.

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[59] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-05-1428, Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation (September 1, 2006).

[60] *Id*. at. 29.

Enbridge is served by Otter Tail off 115 kV lines. Enbridge and MCC proposed that two separate rate classes, transmission and sub-transmission, be established. The proposed change would be based on functionalizing costs in a manner that allocates none of the lower voltage transmission costs to Enbridge. Enbridge argued that it should not contribute to the cost of lower voltage facilities unless Otter Tail demonstrates that they provide meaningful ongoing or emergency support for their pumping stations.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Otter Tail's use of "rolled-in" rates was appropriate for its Minnesota customers, resulted in reasonable rates for all Otter Tail customers, and that no sub-transmission category as recommended by Enbridge and MCC need be established.

D. Commission Analysis and Action

The Commission accepts, adopts and incorporates the findings of the ALJ, that all of Otter Tail's Minnesota customers – including Enbridge – benefit from the use of "rolled-in" rates, and no sub-transmission category need be established. The use of rolled in rates for transmission customers results in reasonable rates for all of Otter Tail's customers.

Otter Tail amply demonstrated that its lower voltage 41.6 kV and 69 kV facilities in the Bemidji area are used during outage of higher voltage transmission, in order to maintain adequate transmission service quality to the area. This clearly benefits Enbridge. Otter Tail also demonstrated that it was able, through its lower voltage facilities, to improve line flow by 10 percent to two of Enbridge's locations, 25 percent to another Enbridge location and by 50 percent to yet another location. Using the lower voltage facilities, Otter Tail was able to restore voltage from 90 percent of normal to 97 percent of normal at one of those locations, which is necessary to meet the North American Electric Reliability Association certification requirements. Absent the ability to rely on the lower voltage transmission facilities to meet NERC standards, substantial and costly 115 kV facility additions would be required, which would be passed on to Minnesota customers, including Enbridge.

Finally, as recognized by the ALJ, adoption of Enbridge's and MCC's analysis would result in different rates for different areas, based on whether an area was served by a 115 kV or lower voltage. The Commission has not previously established retail rates based on this "upstream/downstream" basis, and does not see fit to do so in this rate case.

XXXIV. Allocating Production Plant Costs Between Demand and Energy

A. Introduction

In allocating revenue responsibility, the Commission considers the demand costs and energy costs associated with each class.

Electric utilities incur both fixed and variable costs. The costs of building a generator are generally fixed; they do not change in proportion to the amount of energy generated. In contrast, many operating costs are variable; they change depending on how much the plant is operated. Because a utility must build its plant with sufficient capacity to supply the electricity required by customers even on days of peak demand, fixed plant costs are typically regarded as demand-related costs. In contrast, energy-related costs – such as the cost of fuel or electricity purchased from other generators – are typically variable.

But not all energy-related costs are variable. For example, a utility may install a generator that is expensive to build but uses inexpensive fuel (typical of a "baseload" generator). In this case, the choice to incur extra building costs may be understood as a substitute for incurring extra fuel costs.

Whether to characterize costs as related to energy or demand influences class allocations because a utility incurs a different level of demand and energy-related cost for each customer class. The choice to characterize fixed cost as energy-related benefits the Residential class, which tends to have a low load factor, or ratio of average usage to peak usage. The choice to characterize fixed costs as demand-related benefits the high load factor customers.

The CCOSS determines how Otter Tail's production plant investment (fixed) costs and related operating expenses are assigned to various classes of ratepayers. Different methodologies assign production plant costs based on class energy usage and peak demand usage. The selection of methodology is critical to a determination of what portion of fixed production costs is to be attributed to meeting demand and allocated to the capacity/demand component of rates and what portion attributed to providing energy and allocated to the energy component of rates.

Otter Tail utilized an equivalent peaker methodology to assign production plant costs. MCC proposed use of the breakeven methodology to allocate production plant costs.

B. Positions of the Parties

Otter Tail's rate design allocates plant costs to customer classes using the same classification methods as were used in the CCOSS approved in the Company's 1986 rate case. The Company accepted two modifications to the CCOSS proposed by OES – an adjustment to the D_1 factor and the allocation of the Company's conservation expenses.

Otter Tail used an equivalent peaker methodology to determine the portion of production plant costs to treat as demand versus energy costs. The Company asserted that its equivalent peaker methodology was approved for use in the Company's 1986 rate case, as well as in Xcel Energy's previous seven rate cases. The equivalent peaker method reflects the fact that baseload plants, rather than peakers, are built when there is sufficient need for energy to justify the higher capital costs of a baseload plant. As a result, the portion of baseload fixed cost that exceeds the fixed cost of a peaking plant should be allocated on the basis of energy and not demand.

MCC proposed utilizing a breakeven methodology for allocating production plant costs. The breakeven methodology reallocates production plant costs from energy to demand, and benefits customer classes that use more energy per unit of demand, i.e., high load factor customers. MCC asserted that use of the breakeven methodology would shift $942,000 in cost responsibility away from the high load factor customers in the Large General Service class to lower load factor classes and customers, such as the Residential class.

MCC asserted that the proposed Big Stone II plant would be built to meet peak demand rather than energy needs, arguing that baseload plant costs should be recovered as demand cost components.

The OES agreed with Otter Tail, that use of the equivalent peaker methodology to classify production plant costs is reasonable. The OES asserted that MCC's argument regarding the proposed Big Stone II baseload plant is irrelevant to the issue of how to classify existing production plant costs in this rate case between demand and energy related costs. Instead, MCC's argument concerns the resource needs of the utility rather than the production of those costs.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with the Company's position, supported by the OES, that the equivalent peaker methodology should be used to allocate production plant costs between demand and energy.

D. Commission Action

The Commission accepts, adopts and incorporates the findings of the ALJ on this issue. Otter Tail's equivalent peaker methodology of allocating plant costs between energy and demand related components was approved for use in the Company's 1986 rate case, and the Company has established that it is appropriate for use here. Otter Tail established that it is the need for both capacity and low-cost energy in excess of that provided by a peaking facility that justifies incurring the higher capital costs associated with a baseload plant.

While the MCC and the Company agree that, from a resource planning perspective, a baseload plant will be built once the operating hours exceed those appropriate for a peaking plant, that agreement does not support MCC's recommendation to use a breakeven analysis for purposes of the Company's CCOSS. Instead, there is not a necessary correlation between a resource planning decision and the determination of what is demand-related cost in a cost of service study.

Further, under the methodology proposed by Otter Tail, 61.1 percent of the production plant is treated as energy-related, while, under the breakeven analysis, MCC treated only 16 percent of the production plant as energy related. MCC"s treatment is extreme, and will not be adopted herein. No commonly used embedded cost of service method, other than treating all fixed costs as demand-related, would define such a large share of production fixed costs as demand-related.

Finally, the use of the equivalent peaker methodology has been approved for allocation of production costs by other Minnesota utilities.

XXXV. Declining Block Rates

A. Introduction

Otter Tail's tariffs currently contain declining block rate structures for several of its rate classes. Declining block rates are a pricing mechanism that affords a lower rate for electricity consumption above a set threshold. Thus, as a customer increases usage, the energy charges decrease per unit, encouraging customers to use more energy. The use by utilities of declining block rates has been significantly reduced or eliminated in recent years, due to an increased conservation awareness.

The question posed is at what point, if any, are declining block rates just and reasonable.

B. Positions of the Parties

Otter Tail initially proposed eliminating declining rate structures from all but four of its rate classes. In response to the OES's recommendation to eliminate all declining block rates, the Company agreed to phase out declining rates from two of the remaining four rate classes – the general service 20 kW and greater and large general service rate classes.

The Company's revised proposal would retain block rates for only the following rate classes: residential and general service under 20 kW. Otter Tail substantially reduced the declining block rate features for these remaining two, and indicated that it will propose the elimination of these block rates in its next rate case.

Otter Tail acknowledged that elimination of all declining block rates would satisfy several of its rate structure objectives, such as the objectives to reflect marginal costs and promote efficient use of resources and conservation. It offered its more gradual approach to smooth the transition to more economically efficient rates and to mitigate the rate impacts associated with this rate design change.

The OES recommended that the Company completely eliminate its remaining declining block rates for all of its customer classes. The OES asserted that Otter Tail's declining block rates contravene key criteria in establishing a reasonable rate design – that of encouraging economically efficient energy use and promoting conservation.

The MCC took no position on residential declining block rates, but recommended that the large general service declining block rates be maintained in this rate case.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission accept Otter Tail's proposal to retain declining block rates for residential service and general service less than 20 kW, finding it less abrupt than the OES's proposal. The ALJ found that Otter Tail's more graduated approach would help smooth the transition to more economically efficient rates and to mitigate the rate impacts associated with this rate design change.

The ALJ also recommended that the Commission adopt Otter Tail's proposal to eliminate declining block rates for the large general service customers, despite MCC's arguments to the contrary.

D. Commission Action

The Commission respectfully disagrees with the conclusion of the Administrative Law Judge to maintain declining block rates for residential service and general service less than 20 kW. The Commission appreciates the Company's recognition that declining block rates must be phased out. However, the Commission concurs with the OES that declining block rates raise serious policy issues, and must be fully eliminated from Otter Tail's rate structure as a part of this rate case.

First, the Commission takes this action because declining block rates conflict with the statutory directives to encourage economically efficient energy use and to promote energy conservation found in Minn. Stat. § 216B.03. This statutory provision requires that "to the maximum reasonable extent" rates must encourage energy conservation as well as further other statutory goals. Thus, eliminating declining block rates is necessary to comply with this legislative directive.

Second, declining block rates prevent a customer from receiving the price signals that are necessary for the customer to make choices about the use of energy. The declining block rate sends the customer the signal that production costs decrease after the customer has reached a certain level of consumption. Since energy costs do not vary with the customer's consumption, such information does not enable the consumer to make an accurate link between consumption and cost. Declining block rates, in contrast, encourage additional consumption, and are not appropriate in Minnesota, where conservation is a high priority.

Nor should eliminating declining block rates result in impermissible rate shock. As declining block rates are usage-based charges, it follows that rate impacts will vary based upon usage. While it is clear that the full elimination of declining block rates for higher usage customers will have an impact on rates,[61] that cannot be the only impact considered. Much of the impact on rates

[61] The record establishes that OES's proposal results in smaller rate increases for low usage and average usage customers than Otter Tail's proposal. *See*, updated Griffing Exhibit

increases for these customers stems from the fact that rates are also increasing, and not just from elimination of declining block rates. Further, the lessened impact on low and average residential customers further supports the elimination of declining block rates at this time.

Moreover, even Otter Tail's proposal would only serve to temporarily postpone elimination of declining block rates until its next rate case. Conservation in energy usage is a goal that should not be unnecessarily postponed, particularly when confronted with the rapidly rising costs associated with energy in today's market. No cost justification has been presented for charging customers less for greater use of electricity.

Further, the Commission's revenue requirement decisions in this case have substantially reduced the revenue deficiency, so rate impacts will be correspondingly reduced.

The Commission recognizes that declining block rates raise serious policy issues in today's energy market, conflict with the statutory directive to encourage energy conservation, and give customers inaccurate cost information by telling them that production costs decrease when consumption rises. The Commission will herein re-establish that clear link between consumption and cost. For these reasons, the Commission will act now to eliminate declining block rates for Otter Tail.

XXXVI. Residential Customer Charge

A. Background

Otter Tail recovers its cost of serving residential customers through a combination of a monthly customer charge, paid by any customer connected to its utility system, and a usage charge for the electricity consumed. The customer charge is designed to recover fixed costs that do not vary with usage, such as constructing and maintaining infrastructure, reading meters, and conducting billing and collection services. The monthly customer charges are set by class and may differ by zones within a utility's service area.

The customer charge has two main functions, one practical and one grounded in ratemaking policy. Its practical function is to help stabilize utility revenues and reduce the risk that the utility will over or under recover its revenue requirement due to fluctuations in usage and sales. Its ratemaking function is to ensure that each customer bears responsibility for a certain level of the Company's fixed costs regardless of usage.

The issue posed is what constitutes a just and reasonable level for the customer charge component of the Company's residential rates. Otter Tail's existing urban residential customer charge is $6.15 and the rural rate is $7.15.

B. Positions of the Parties

(May 6, 2008)(MFG - S-4).

Otter Tail has not raised its customer charge for residential rates in over 20 years. The Company advocated increasing the residential customer charge to $8.00 for both the urban and rural residential rate. The Company's marginal cost study suggested the cost of providing residential customer service is $11.83, resulting in a gap between that cost and the current $6.15/$7.15 monthly customer charge.

Otter Tail asserted that because the customer charge is below the customer cost, the Company must recover the unrecovered customer costs through the usage, or energy, charge. The Company argues that as a result, customers with more than average usage pay more than their proportionate share of these costs, which constitutes an intra-class subsidy. Otter Tail proposed to increase the customer charge for all residential customers to $8.00 as a means to address this issue.

The OES supported Otter Tail's proposal to move the customer charge to $8.00, but also advocated an increase to $8.50 in two years with a corresponding decrease in the variable energy charge at that time. The OES asserted that its position balances conservation and efficiency, while also taking into account non-cost factors such as avoiding rate shock. The OES argued that its position moves the customer charge closer to cost, reduces intra-class subsidies, and increases fairness and efficiency.

The RUD-OAG argued that the customer charge should be set at $6.15 for all residential customers. The RUD-OAG maintained that any increase in the customer charge contravenes the directive in Minn. Stat. § 216B.03 to promote conservation, as higher customer charges decrease the incentive to conserve. The RUD-OAG also maintained that the proposed increase constitutes a 28% rise over the existing charge and that such an amount would cause rate shock.

C. Recommendation of the Administrative Law Judge

The ALJ recommended approval of Otter Tail's proposal to increase its residential charge to $8.00, finding that the increase appropriately assigns costs to the residential class, while not resulting in customer confusion or rate shock.

D. Commission Action

The Commission concurs with the Administrative Law Judge on this issue and accepts and adopts his findings, conclusions, and recommendations. Otter Tail has amply demonstrated that an increase in the residential basic charge from $6.15 per month to $8.00 per month is an appropriate adjustment to balance the need to recoup the costs of serving the residential class of customers without interclass subsidies, with the need to encourage conservation, avoid rate shock, and account for other factors between rate classes.

The Commission has carefully reviewed the record and the arguments of the parties and concurs with the ALJ on these issues; it accepts, adopts and incorporates Findings 442 through 450 and Conclusion 24.

XXXVII. Time-of-Day and Standby Rates

A. Introduction

Otter Tail proposed modifications to its Large General Service Time of Day (LGS-TOD) rate design and Standby Service Rate Design – which is based upon the rate design for the proposed LGS-TOD rate. LGS-TOD rate schedules charge varying rates based upon the time of day the energy is used. The question posed is how the Company's time-of-day and standby rates should be structured, especially in terms of reflecting marginal costs and generating costs at different times of day.

B. Positions of the Parties

1. LGS-TOD Rate

Otter Tail asserted that its proposed LGS-TOD rate makes several improvements to its existing rate: it reflects a four-month summer/eight month winter seasonal pattern of costs (instead of two six month seasons); it includes three diurnal periods – peak, shoulder and off-peak (instead of two); and it reflects the Company's marginal costs. No party disputed the seasonal change.

MCC recommended redesigning the LGS-TOD rate to: 1) base voltage level energy discounts on loss differentials; 2) base voltage level demand discounts on fixed embedded costs associated with each level of service; 3) use higher demand charges to signal known future investment in Big Stone II and transmission expansion; and 4) base the remaining revenue to be collected from energy charge (after accounting for an appropriate level of demand charges) on a marginal energy cost analysis using actual embedded cost data.

MCC and Enbridge objected to the proposed three diurnal pricing periods. MCC opposed the move to three periods, and claimed that customers may have trouble keeping track of the various periods. Enbridge criticized the change to three periods, not because of complexity, but because they are different from other utilities from which it takes service, and may complicate load management across its multi-state pipeline.

Enbridge also recommended that all holidays be treated as off-peak.

Otter Tail responded to each objection of MCC and Enbridge.

2. Standby Service Rate

Otter Tail proposed a Standby Service rate which essentially reflects its current offering and is based on the rate design for the proposed LGS-TOD rate. The changes reflect updated seasonal and costing periods and are based upon Otter Tail's marginal costs. The Company asserted that the proposed additions improve the price signals inherent in the rate and reflect the similar changes that have been made to the LGS-TOD rate.[62]

MCC argued that the proposed additions are very complicated compared to the Company's current rate, arguing that the Company's current Standby Service rate structure should be retained. MCC also argued that Standby Service customers should be allowed to choose their supplemental service rate rather than being required to take supplemental service under the LGS-TOD rate. Further, MCC argued that retaining the current Standby Service rate is important to the future of distributed generation. Finally, MCC asserted that a sub-transmission voltage level should be added to the Standby Service rate schedule.

C. Recommendations of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission adopt Otter Tail's proposed LGS-TOD and Standby Service rates.

D. Commission Action

The Commission accepts, adopts, and incorporates the findings and conclusions of the Administrative Law Judge on these issues. Otter Tail's proposed LGS-TOD rate and Standby Service Rate will be accepted. These rates are based on marginal cost and are designed to encourage the efficient use of resources.

The Commission considered MCC's proposed redesign modifications to the proposed LGS-TOD rate, but will not accept them. The first two recommendations – to base voltage level energy discounts on loss differentials and to base voltage level demand discounts on fixed embedded costs associated with each level of service – are apparently based on an assumption that customers served at different voltage levels within a class should pay different rates. The Commission has found in this rate case that such distinctions in transmission voltage are inappropriate. The Commission also finds that these two steps to redesign the LGS-TOD rate are inappropriate.

Further, MCC's recommendation to use higher demand charges to signal known future investment in Big Stone II and transmission expansion implicitly assumes that capacity costs should be based on future costs instead of the market cost of capacity during the period rates will be in effect. The Commission has found that Otter Tail's marginal cost study methodology is appropriate, and it would be inappropriate to redesign the LGS-TOD rate on this basis.

Finally, MCC's recommendation bases one rate component – demand charges – on the cost of future capacity additions, and another component – energy charges – on current marginal costs. The Commission agrees with the ALJ that this approach is likely to result in an inefficient signal to consume more energy in all hours except the hour in which the customer set its billing demand.

[62] Otter Tail currently has no customers taking service under its Standby Service rate.

The Commission also finds that the Company's proposed modification of its Standby Service rate structure merely reflect updated seasonal and costing periods, and are based on marginal costs, which improve the overall efficiency of the rates. Customers likely to take service under the Standby Service rates are larger, sophisticated businesses, which, by the nature of the rate, will have on-site generation that they manage. Thus, these businesses will likely have experts managing their energy use and have the ability to understand the rates.

XXXVIII. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue deficiency for the 2006 test year of $3,813,114 as shown below:

REVENUE SUMMARY

Test Year Ending December 31, 2006

Rate Base	$	204,888,081
Rate of Return		8.33%
Required Operating Income	$	17,067,177
Test Year Operating Income	$	14,831,548
Operating Income Deficiency	$	2,235,629
Revenue Conversion Factor		1.705611
Gross Revenue Deficiency	$	3,813,114

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional rate base for the 2006 test year is $204,888,081 as shown below:

RATE BASE

Test Year Ending December 31, 2006

Utility Plant in Service	$ 462,977,496
Reserve for Depreciation	(221,363,544)
Net Utility Plant in Service	$ 241,613,952
Construction Work in Progress	7,602,461
Plant Held for Future Use	14,157
Accumulated Deferred Income Taxes	(40,094,522)
Working Capital	
Cash Working Capital	1,934,122
Materials and Supplies	5,722,799
Fuel	3,203,404
Prepayments	(14,816,072)
Other	(292,220)
Total Average Rate Base	$ 204,888,081

C. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the 2006 test year under present rates is $14,831,548 as shown below:

OPERATING INCOME STATEMENT
Test Year Ending December 31, 2006

Revenues:		
Retail Revenues	$	131,338,179
Other Operating		17,656,555
Total Revenues	$	148,994,734
Expenses:		
Production, Fuel, Purchased Power	$	74,533,381
Transmission		5,330,005
Distribution		6,283,425
Customer Accounting		4,680,629
Customer Information		4,022,888
Administrative & General		16,803,612
Sales		361,258
Other Expense		92,377
Depreciation & Amortization		13,015,289
Taxes:		
Property		4,748,410
State & Federal Income		6,968,995
Deferred Income		(1,616,131)
Other		(572,102)
Total Expenses	$	134,652,036
Income Before AFUDC	$	14,342,698
AFUDC		488,850
Income With AFUDC	$	14,831,548

XXXIX. Compliance Filings Required

The Commission will require the Company to make a compliance filing within 30 days of the date of this Order showing the final rate effects of the decisions made here and proposing a plan for refunding the difference between the amounts it collected in interim rates and the amounts it is authorized to collect in final rates. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

The Commission will so order.

ORDER

1. Otter Tail Power Company is entitled to increase gross annual revenues from Minnesota retail sales by $3,813,114, in order to produce gross annual jurisdictional Total Operating Revenues of $152,807,848.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth herein.

3. At least 30 days before the filing of its next rate case, and in any event no later than June 20, 2013, Otter Tail shall file a fully developed study of its transmission system under the Commission's *Boundary Order* in docket E-999/CI-99-1261.

4. In its next general rate case filing, Otter Tail shall provide an embedded class cost of service study as well as a marginal cost study. The Company shall also develop and use an E8760 Allocator for Class Cost of Services Purposes in its next rate case and shall continue to investigate the costs and benefits of developing an E8760 Allocator for other purposes.

5. In its next general rate case filing, Otter Tail shall provide a new energy loss study.

6. Within 30 days of the date of this Order, the Company shall make a compliance filing implementing the decisions made herein and containing at least the following items:

   A. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:

      1. A breakdown of Total Operating Revenues by type.

      2. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity, including but not necessarily limited to the items set forth below.

      3. Total revenue by customer class.

      4. Total number of customers, the customer charge and total customer charge revenue by customer class.

5. For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of electricity, the non-electricity unit margin, and the total energy and demand related sales revenues.

6. Revised tariff sheets incorporating authorized rate design decisions.

7. Proposed customer notices explaining the final rates and the monthly basic service charge.

B. A revised base cost of energy to be put into effect with final rates, together with supporting schedules incorporating any changes made as a result of this rate case and revised fuel clause tariffs.

C. A calculation of the Conservation Improvement Program (CIP) conservation cost recovery charges (CCRC) based on the decisions made herein and schedules detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor), and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

D. Copies (revised as necessary) of all standard customer service agreements and contracts for inclusion in the Company's tariff book.

E. A proposal to make refunds of interim rates, including interest calculated at the average prime rate, to affected customers.

7. Comments on the compliance filing required in the preceding paragraph shall be filed within 15 days of the date it is filed.

8. The Company shall record and track all incentive compensation costs recovered in rates and all incentive compensation paid to employees, to permit the refund of any over-recovered amounts to ratepayers.

9. The Company shall record and track all rate case expenses recovered in excess of the three-year amortization amount authorized herein, to permit the refund of over-recovered amounts to ratepayers.

10. In future Jurisdictional Reports the Company shall report all revenues and expenses associated with asset-based wholesale margins. The Company shall also work with the Office of Energy Security to (a) ensure accuracy in reporting both asset-based and non-asset based wholesale margins and (b) clarify the terms, conditions, and time frames under which it will provide the Office of Energy Security with the information it requires.

11. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mark E. Oberlander for

Burl W. Haar
Executive Secretary

(S E A L)

This document can be made available in alternative formats (i.e. large print or audio tape) by calling 651.201.2202 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1.800.627.3529 or by dialing 711.

STATE OF MINNESOTA)
)SS
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, Margie DeLaHunt, being first duly sworn, deposes and says:

That on the 1st day of August, 2008 she served the attached

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER.

MNPUC Docket Number: E-017/FR-07-1178

_XX_ By depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid

_XX_ By personal service

_XX_ By inter-office mail

to all persons at the addresses indicated below or on the attached list:

Commissioners
Carol Casebolt
Peter Brown
Eric Witte
Marcia Johnson
Kate Kahlert
Louis Sickmann
Michelle Rebholz
Jerry Dasinger
Tracy Smetana
Janet Gonzalez
Stuart Mitchell
Mary Swoboda
Jessie Schmoker
DOC Docketing
AG - PUC
Julia Anderson - OAG
John Lindell - OAG

Margie DeLaHunt

Subscribed and sworn to before me,

a notary public, this 1 day of

August, 2008

Robin Benson
Notary Public

ROBIN J. BENSON
NOTARY PUBLIC-MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2010

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Dept. of Commerce

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