

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd  
J. Dennis O'Brien  
Thomas Pugh  
Phyllis A. Reha  
Betsy Wergin

Chair  
Commissioner  
Commissioner  
Commissioner  
Commissioner

In the Matter of the Application of Minnesota  
Power for Authority to Increase Rates for  
Electric Service in Minnesota

ISSUE DATE: November 2, 2010

DOCKET NO. E-015/GR-09-1151

FINDINGS OF FACT, CONCLUSIONS,  
AND ORDER

**PROCEDURAL HISTORY**

**I. Initial Filings**

On November 2, 2009, Allete, Inc. d/b/a Minnesota Power filed this general rate case seeking an annual rate increase of some \$80,885,213, or approximately 18.9%. The filing included a proposed interim rate schedule.

On December 30, 2009, the Commission issued three orders in this case: one finding the rate case filing substantially complete and suspending the proposed final rates; one referring the case to the Office of Administrative Hearings for contested case proceedings; and one setting interim rates for the period during which the rate case was being resolved. Also on December 30, the Commission issued an order setting a new base cost of energy for the period during which interim rates would be in effect.<sup>1</sup>

**II. The Parties and Their Representatives**

The following parties appeared in this case:

- Minnesota Power, represented by Christopher D. Anderson, Associate General Counsel, Minnesota Power; and Sam Hanson, Thomas Erik Bailey, and Elizabeth M. Brama, Briggs and Morgan, P.A.
- Office of Energy Security of the Minnesota Department of Commerce (the OES), represented by Julia Anderson and Linda S. Jensen, Assistant Attorneys General.

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<sup>1</sup> *In the Matter of the Petition of Minnesota Power for Approval of a New Base Cost of Energy*, E-015/MR-09-1152, Order Setting New Base Cost of Energy (December 30, 2009).

- Residential and Small Business Utilities Division of the Office of the Minnesota Attorney General (RUD-OAG), represented by Ronald M. Giteck and William T. Stamets, Assistant Attorneys General.
- ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise, Inc.; Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; NewPage Corporation; PolyMet Mining, Inc.; Sappi Cloquet, LLC; USG Interiors, Inc.; United States Steel Corporation (Keewatin Taconite and Minntac Mine); and United Taconite, LLC (collectively, the Large Power Intervenors or LPI), represented by Robert S. Lee and Andrew P. Moratzka, Mackall, Crouse & Moore, PLC.
- Minnesota Chamber of Commerce, represented by Bride Seifert, rate case intern.
- Energy CENTS Coalition, represented by Pam Marshall, Executive Director.
- Izaak Walton League of America – Midwest Office, Fresh Energy, and Minnesota Center for Environmental Advocacy (collectively, Joint Intervenors), represented by Elizabeth Goodpaster, Staff Attorney, Minnesota Center for Environmental Advocacy.

### **III. Proceedings Before the Administrative Law Judge**

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Kathleen D. Sheehy to hear the case.

#### **A. Public and Evidentiary Hearings**

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings and initial and reply briefs after the close of evidentiary hearings. The ALJ held evidentiary hearings in St. Paul on May 17-19, 2010.

The ALJ also held six public hearings in the case, at the times and locations set forth below:

- Eveleth, April 13, 2010 – 2:00 p.m. and 7:00 p.m.
- Duluth, April 14, 2010 – 2:00 p.m. and 7:00 p.m.
- Grand Rapids, April 21, 2010 – 7:00 p.m.
- Little Falls, April 22, 2010 – 7:00 p.m.

Some 110 members of the public attended the public hearings, and 89 members of the public submitted written comments to the ALJ. Nearly all opposed any significant rate increase, and many emphasized the disruption and hardship that could result from rate increases during the current economic downturn. Many objected to the timing of this rate case, which was filed one day after final rates were implemented in the Company's last rate case.

Several persons expressed concern about executive compensation, corporate travel and entertainment costs, and advertising and lobbying expenses. Several persons expressed disagreement with statutory requirements that utilities invest in renewable resources.

Representatives of the Minnesota Citizens Federation Northeast and several other commenting parties opposed the Company's proposal to require residential customers to demonstrate financial need to qualify for the Lifeline rate design currently applied to all residential accounts. At the same time, some commenters challenged the fairness of that rate design, which provides rate relief to lower-usage customers by billing the first 350 kWh used at significantly lower rates than kWh used over that amount.

Two municipalities, Duluth and Long Prairie, and several Duluth businesses filed letters emphasizing that they were facing severe budget challenges and that a rate increase would compound those challenges. Several economic development organizations filed letters supporting rate recovery of the Company's economic development expenses.

Several community service organizations, the Duluth Chamber of Commerce, and the University of Minnesota-Duluth filed comments supporting rate recovery of the Company's charitable contributions based on its historical giving patterns, not on its 2009 charitable contributions, which they argued were unusually low due to anomalous economic conditions.

### **B. Revised Revenue Deficiency**

In April 2010, the Company filed rebuttal testimony revising its projected revenue deficiency – and its corresponding rate increase request – from \$80,885,213 to \$71,800,000. The Company reported that it had revised its sales and revenue forecasts upward based on new information from its Large Power customers, who account for 64% of its retail revenues.

### **C. Multi-Party Stipulation**

In May 2010, five of the seven parties to this case<sup>2</sup> filed a Stipulation and Settlement Agreement resolving between themselves the following issues:

- Projected retail and wholesale margins for the 2010 test year.
- Jurisdictional allocations for test-year retail and wholesale sales.
- Return on equity, capital structure, and cost of debt.
- Specific operating and maintenance expenses for generating units 3 and 4, Boswell Energy Center.
- Environmental retrofit costs for generating unit 3, Boswell Energy Center.

The agreement also contained a provision requiring Minnesota Power to file detailed information about the financial impact of future increases in Large Power load for the purpose of permitting the other parties to petition the Commission for across-the-board rate reductions to reflect the revenue increases those load increases represent.

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<sup>2</sup> Those parties are the Company, the OES, the Minnesota Chamber of Commerce, the Large Power Intervenor, and the Energy CENTS Coalition. The parties who did not join in the stipulation and settlement were the RUD-OAG and the Joint Intervenor.

The RUD-OAG opposed portions of the stipulation and settlement, which the ALJ recommended that the Commission accept.

#### **IV. Proceedings Before the Commission**

On August 17, 2010, the Administrative Law Judge filed her Findings of Fact, Conclusions and Recommendation (the ALJ's Report).

On September 1, 2010, the Company, the OES, the RUD-OAG, the Minnesota Chamber of Commerce, the Large Power Intervenors, and the Joint Intervenors filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. Rules, part 7829.2700.

On September 27 and 29, 2010, the Commission heard oral argument from and asked questions of the parties. On September 29, the record closed under Minn. Stat. § 14.61, subd. 2.

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.<sup>3</sup> 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.<sup>4</sup> 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. . . .

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<sup>3</sup> Minn. Stat. § 216B.16, subs. 4, 5, and 6.

<sup>4</sup> *In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 10 (Minn. 1998).

## **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 tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs 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:

[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.<sup>5</sup>

## **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.<sup>6</sup> Any doubt as to reasonableness is to be resolved in favor of the consumer.<sup>7</sup>

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<sup>5</sup> *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).

<sup>6</sup> Minn. Stat. § 216B.16, subd. 4.

<sup>7</sup> 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:

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.”<sup>8</sup> (Citation omitted.)

## II. Summary of the Issues

The parties worked effectively to narrow the issues and, by the date of oral argument, only the issues listed below remained contested:

### *Adequacy of Company Filings*

- *Projected Test Year* – Is the Company’s fully projected test year adequately supported and sufficiently reliable for ratemaking purposes or should the rate case be dismissed?
- *Revised Sales and Revenue Forecasts* – Are the revised sales and revenue forecasts filed by the Company on rebuttal explained and supported with enough detail to permit informed decision-making and reliable ratemaking?
- *Support for Employee Expenses Other than Salary and Benefits* – Do alleged deficits in evidentiary support for employee expenses other than salary and benefits require dismissing the rate case?
- *Alleged Gaps in Test Year Schedules* – Do alleged gaps in the Company’s test-year revenue and cost of service schedules require dismissing the rate case?

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<sup>8</sup> *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).

### **Multi-Party Stipulation and Settlement**

- *Large Power Sales Forecast* – Does the stipulation and settlement incorporate a reasonable forecast of Large Power sales and revenues?
- *Wholesale Margins* – Do the test-year wholesale margins incorporated into the stipulation and settlement adequately compensate ratepayers for the cost of generating the wholesale energy?
- *Jurisdictional Cost Allocations* – Are the wholesale/retail cost allocations reflected in the stipulation and settlement just and reasonable?
- *Cost of Variable-Rate Debt* – Is the cost of variable debt incorporated into the stipulation and settlement just and reasonable?
- *Margin Impact Analysis Filings* – Should the Commission accept the Stipulation and Settlement’s provisions requiring Minnesota Power to file detailed information about the financial impact of future increases in Large Power load for the purpose of permitting the other parties to petition the Commission for across-the-board rate reductions to reflect the revenue increases those load increases represent?
- *Stipulation and Settlement as a Whole* – Is the stipulation and settlement as a whole reasonable, in the public interest, and supported by substantial evidence?

### **Rate Base**

- *Construction Work in Progress* – Has the Company demonstrated that it is just and reasonable to add to the purchase price of the Square Butte transmission line some \$2,890,549 in Construction Work in Progress costs?
- *Capital Investments in Boswell 4 Generating Unit* – Has the Company demonstrated that it is reasonable and prudent to make some \$75,000,000 in capital investments in the Boswell 4 generating facility?

### **Operating and Maintenance Costs**

- *Pension Expense* – Has the Company properly calculated test-year pension expense, given the historical volatility of pension costs?
- *Other Post-Retirement Benefits* – Has the Company demonstrated that all claimed costs related to post-retirement benefits other than pension are reasonable, prudent, and otherwise eligible for rate recovery?
- *Incentive Compensation Costs* – Has the Company demonstrated that its incentive compensation costs are reasonable, prudent, and otherwise eligible for rate recovery?

- *Employee and Board Member Expenses Other than Salary and Benefits* – Has the Company demonstrated that test-year expense related to employee and Board member travel, lodging, meals, entertainment, employee recognition, and similar functions are reasonable, prudent, and otherwise eligible for rate recovery?
- *Costs of Corporate Jet* – Has the Company demonstrated that all claimed costs related to its corporate jet are reasonable, prudent, and otherwise eligible for rate recovery?
- *Economic Development Costs* – Has the Company demonstrated that all claimed costs related to economic development are reasonable, prudent, and otherwise eligible for rate recovery?
- *Current Rate Case Expenses* – Has the Company demonstrated that all claimed costs related to this rate case are reasonable, prudent, and otherwise eligible for rate recovery?
- *Costs of Defending Environmental Protection Agency Enforcement Action* – Has the Company demonstrated that all claimed costs related to defending a pending enforcement action by the Environmental Protection Agency are reasonable, prudent, and otherwise eligible for rate recovery?
- *Charitable Contributions* – Has the Company demonstrated that the amount claimed in test-year charitable contributions reasonably represents its probable charitable contributions during the period that final rates will be in effect?
- *Lobbying Expenses* – Has the Company demonstrated that its lobbying costs are reasonable, prudent, and otherwise eligible for rate recovery?

#### **Filing Requirements for Next Rate Case**

- *Sales Forecast* – Besides requiring the Company to continue working with the OES on sales forecasting issues, methodologies, and technologies, should the Commission require the Company to file test year sales forecasts and the data used to prepare them 30 days in advance of its next rate case filing?
- *Class Cost of Service Study* – Should the Commission require the Company to change its treatment of income tax expense in its next Class Cost of Service Study to calculate and assign income taxes on the basis of net taxable income attributable to each customer class, instead of present rate revenues attributable to each customer class?

#### **Rate Design**

- *Large Power Rate Design Settlement* – Should the Commission approve the rate design settlement between the Company and its Large Power customers under which the Company withdrew its proposal to add a 50% take-or-pay requirement to its Large Power tariff?

- *Peak and Average Cost Allocation Method* – Is the peak and average cost allocation method used in the Company’s Class Cost of Service Study a reasonable starting point for allocating costs among customer classes?
- *E8760 Allocator* – Is the E8760 allocator used in the Company’s Class Cost of Service Study a reasonable starting point for allocating costs among customer classes?
- *Class Revenue Apportionment* – How should the final revenue requirement be allocated among customer classes?
- *Residential Rate Design* – Should Minnesota Power retain its traditional Lifeline residential rate structure, with a small usage allowance included in the customer charge and two ascending usage blocks with ascending rates?
- *Customer Charge for Seasonal, Dual Fuel, and Controlled Access Residential Customer Classes* – What is the appropriate level of customer charge for these three customer classes?

### **III. Administrative Law Judge’s Report**

The Administrative Law Judge’s Report is well reasoned, comprehensive, and thorough. The ALJ held three days of evidentiary hearings and six public hearings. She reviewed the testimony of some 30 expert witnesses and examined over 100 exhibits. She made some 390 findings of fact and conclusions and made recommendations on all stipulated and contested issues based on those findings and conclusions.

Having itself examined the record and having considered the report of the Administrative Law Judge, the Commission concurs in most of her 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 her findings, conclusions, and recommendations.

The issues disputed among the parties are addressed below.

### **IV. The Projected Test Year and the Overall Adequacy of the Company’s Filing**

The RUD-OAG challenged the overall adequacy of the Company’s filing, claiming that its use of a fully projected test year, coupled with its revision of its sales forecast on rebuttal, its alleged failure to adequately support test-year employee expenses, and alleged gaps in its test year schedules, rendered the filing unreliable for ratemaking purposes. These claims will be examined in turn.

#### **A. The Projected Test Year**

##### **1. The RUD-OAG’s Claims**

The RUD-OAG challenged the Company’s use of a fully projected test year – calendar year 2010 – on grounds that projected test years are inherently less reliable than historical test years and are disfavored by the Commission. The RUD-OAG cited in support a Commission decision rejecting

in its entirety Northern States Power Company's 1989 rate case, which used a fully projected test year.<sup>9</sup>

## **2. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge concluded that the Commission has not found historical test years superior to projected test years and has consistently permitted utilities to use either one. She pointed out that the Commission's rejection of the 1989 rate case was not based on the use of a projected test year, but on a failure to substantiate that the projected test year had a clear and substantial link with actual historical experience.

She also found no meaningful similarity between the rejected 1989 rate case filing and this one. The capital budgeting process used in the 1989 case included at least 140 cancelled or uncompleted projects and overestimated actual capital costs by up to 28%; its accuracy and reliability were questioned by nearly every party to the rate case. Here, no party questions the historical accuracy of the Company's capital budgeting process, and disputes mainly involve prudence and policy issues, not the essential accuracy of the Company's figures.

Similarly, in the 1989 rate case, the Commission found that the company's operating and maintenance expenses exhibited roller-coaster characteristics with little or no explanation. Here, the Company's operating and maintenance expenses exhibited decline with a clear explanation – dramatic reductions in retail load and return on common equity in the face of the most severe economic downturn the national economy has experienced in decades. Again, disputes mainly involve the likely extent and effects of the economic recovery on Company revenues, not the reliability of the Company's figures.

## **3. Commission Action**

The Commission concurs with the Administrative Law Judge's findings, analysis, and recommendation.

The fatal defect in the 1989 NSP rate case was not the projected test year, but the absence of factual support for the data in the projected test year. As the Commission explained in rejecting the 1989 case, it had "grave doubts about the accuracy, reliability, and predictive value of the test year budget data submitted by the Company," and it could not set rates based on that data.<sup>10</sup>

Here, the Company has credibly documented the factual basis for its test year budget data, linking projected and historical costs in a manner permitting meaningful, detailed examination by the other parties. While greater precision and clarity remain constant goals – and the Commission will require specific refinements in the data submitted in the next rate case – this filing and the projected test year on which it is based provide a reliable basis for setting rates on a going-forward basis.

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<sup>9</sup> *In the Matter of the Petition of Northern States Power Company for Authority to Increase its Rates*, E-002/GR-89-865, Findings of Fact, Conclusions of Law, and Order (August 27, 1990).

<sup>10</sup> *In the Matter of the Petition of Northern States Power Company for Authority to Increase its Rates*, E-002/GR-89-865, Findings of Fact, Conclusions of Law, and Order (August 27, 1990), at 7.

## **B. The Company's Revised Sales Forecast**

### **1. Introduction**

In its rebuttal testimony the Company filed a revised sales forecast anticipating significant increases in retail sales based mainly on significant increases in the March 2010 nominations (requests for specific amounts of power) from its Large Power customers and secondarily on updated economic data. Since some 60% of the Company's retail load is Large Power load, changes in Large Power sales have a substantial impact on Company revenues.

Based on this revised sales forecast, the Company reduced its claimed revenue deficiency from \$81,000,000 to \$71,800,000 and proposed smaller rate increases for retail customers.

### **2. The RUD-OAG's Claims**

The RUD-OAG claimed that the Company's revision of its sales forecast was further evidence of the fundamental unreliability of its data, that the revised forecast resulted in a different rate case from the one filed, and that the only reasonable response was to deny the Company any rate increase in this proceeding.

### **3. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the revised sales forecast had a solid factual basis, did not demonstrate fundamental flaws in the Company's rate case filing, and did not render the record unrecognizable and incapable of supporting reasoned decision-making.

She pointed out that the revision was caused by economic conditions beyond the Company's control and worked to the benefit of the ratepayers, not the shareholders.

### **4. Commission Action**

The Commission concurs with the Administrative Law Judge's findings, analysis, and recommendation. While a sales forecast revision of this magnitude may present challenges, those challenges are neither insurmountable nor of the Company's making. Nor are they completely avoidable in every case for Minnesota Power.

The Company's sales forecasts are volatile because its sales are volatile – over 60% of its retail generation serves Large Power customers such as taconite plants and paper mills, whose usage fluctuates with the global economy. This heavy concentration of customers marked by high usage and volatility ensures that the Company's sales forecasting process will be both complex and critical to rate-setting. The Commission will continue to monitor the Company's sales forecasting and will require its ongoing cooperation with the OES to refine its forecasting, but forecasting issues are likely to persist, even as the process improves.

Further, the Company provided a solid factual foundation for the revised forecast, which worked to the financial benefit of ratepayers, not shareholders, and was accepted as a reliable starting point for ratemaking purposes by all parties but the RUD-OAG.

For all these reasons, the Commission joins in the findings and recommendations of the ALJ.

### **C. Support for Employee Expenses**

#### **1. The RUD-OAG's Claims**

The Company included in test year expense some \$1,800,000 in employee expenses other than salary and benefits. These expenses were mainly for travel, entertainment, employee recognition, team-building events and initiatives, and gifts marking employee life-events. The RUD-OAG served the Company with a series of information requests seeking explanations and accountings of all amounts spent for these purposes; the Company's responses were inadequately detailed in the RUD-OAG's view. In addition to challenging the amount of these expenses, the RUD-OAG claimed that the lack of detail provided by the Company further demonstrated the fundamental inadequacy and unreliability of its entire rate case filing.

#### **2. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that, while the Company had not met its burden of proof on the rate-recoverability of the entire \$1,800,000 in employee expenses, this failure did not demonstrate any inherent or thoroughgoing unreliability in its budgeting processes, nor otherwise justify invalidating its entire rate case filing.

She pointed out that the Company had made some \$300,000,000 in substantial capital investments since its last rate case and that, even if the entire \$1,800,000 proved to be unsupported, the capital investments alone would still merit examination. She concluded that the appropriate course of action was to examine the employee costs in the same manner as other claimed test-year expenses.

#### **3. Commission Action**

The Commission concurs with the findings, analysis, and recommendations of the Administrative Law Judge.

While the employee expenses merit careful scrutiny – which they receive below – the real issues these expenses raise go to reasonableness and prudence, not to the integrity or accuracy of the Company's accounting and budgeting practices. These expenses do not warrant rejection of this rate case or the projected test year on which it is based.

### **D. Alleged Gaps in the Test Year Schedules**

The RUD-OAG also took issue with how the Company organized, presented, and characterized the information in its test-year revenue schedules and cost of service schedules, mainly on the basis of what it considered discrepancies in Company responses to information requests that were not in the record. The Division argued that these gaps and discrepancies, too, demonstrated the unreliability of the Company's data and projected test year and required the rejection of its entire rate case.

The Administrative Law Judge concluded that the Company's test year schedules did not contain material gaps or discrepancies, even if they were not organized and presented in the manner preferred by the RUD-OAG. The Commission concurs with the findings, analysis, and recommendations of the Administrative Law Judge on this issue.

## **V. The Multi-Party Stipulation and Settlement**

### **A. Introduction**

On May 18, 2010, five of the seven parties to the case filed a Stipulation and Settlement resolving several major issues, including the following:

- Test-year retail and wholesale margins
- Jurisdictional allocations
- Return on equity, capital structure, and cost of debt
- Specific adjustments to the test-year operating and maintenance expense for Boswell generating units 3 and 4
- Test-year environmental retrofit costs for Boswell generating unit 3

The Stipulation and Settlement also contained a provision that, in brief, (a) obligated Minnesota Power to file a "Margin Impact Analysis" detailing the financial impact of each future significant increase in its Large Power load; (b) permitted any party to the Stipulation and Settlement to petition the Commission for an across-the-board retail rate reduction based on that increase; and (c) prohibited any party to the Stipulation and Settlement from opposing that petition on grounds that the relief sought constituted prohibited single-issue ratemaking.

The parties to the Stipulation and Settlement were Minnesota Power, the Office of Energy Security, the Large Power Intervenors, the Energy CENTS Coalition, and the Minnesota Chamber of Commerce.

The RUD-OAG opposed the Stipulation and Settlement, particularly its provisions on retail margins, wholesale margins, jurisdictional cost allocations, the cost of variable-rate debt, and the new Margin Impact Analysis filings and related procedures.

The Commission will examine each of the RUD-OAG's challenges to the Stipulation and Settlement individually, followed by an analysis of the Stipulation and Settlement as a whole.

### **B. Retail Revenues/Large Power Sales Forecast**

#### **1. Introduction**

The Stipulation and Settlement provisions on test-year retail revenues and margins necessarily assume a specific level of retail sales; the RUD-OAG challenges the level of Large Power sales built into the retail sales and revenue analysis.

In initial testimony, the Company, the OES, and the RUD-OAG each filed their own projections of test-year Large Power sales, a key input in determining test-year revenues. When the Company filed its revised – and much higher – Large Power sales forecast, based on higher nominations by

its Large Power customers and improvements in key economic indicators, the OES recommended still larger increases. The RUD-OAG supported the increases recommended by the OES.

The Company then pointed out that the OES projections appeared to assume industrial production levels achievable only under the most favorable economic conditions and that, more important, those projections made no allowance for planned maintenance, seasonal variations in production, scheduled plant shutdowns, and variations in customer load factors.

The OES considered the point well taken and accepted the Company's revised Large Power sales forecast. The RUD-OAG did not, continuing to recommend a higher forecast reflecting maintenance outages alone, not the wider range of outages and load factor reductions accepted by the OES.

## **2. The RUD-OAG's Claims**

The RUD-OAG objected to the Large Power sales forecast on grounds that it was based on a flawed forecasting methodology, was not sufficiently transparent, and did not use data as recent as would be optimal. The Division again claimed that the need to file a revised forecast in itself demonstrated the fundamental unreliability of the entire rate case filing.

The remedy the Division recommended was adopt the OES's revised Large Power sales forecast, minus sales hours lost to maintenance, but to include the other hours the OES agreed would not be sold due to seasonal variations in production, scheduled plant shutdowns, variations in customer load factors, and similar factors.

## **3. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge recommended accepting the Large Power sales forecast introduced by the Company and supported by the OES, finding that the lost hours attributed to seasonal variations in production, scheduled plant shutdowns, and variations in customer load factors were reasonably certain to occur.

## **4. Commission Action**

The Commission concurs with the ALJ's findings, conclusions, and recommendations.

It is reasonable to factor in to the Large Power sales forecast the seasonal variations in production, scheduled plant shutdowns, and variations in customer load factors the Company anticipates, as well as outages for maintenance. It is not reasonable, as the OES conceded, to base forecasted sales on maximum production 365 days per year.

Further, it is not reasonable to reduce the sales forecast to account for unspecified but assumed defects in forecasting methodologies, which may in fact be symmetrical, rather than consistently favoring the Company. As discussed above, forecasting is a complex and iterative process that the Company will be directed to continue to refine in consultation with the OES.

## **C. Wholesale Margins**

### **1. Introduction**

Minnesota Power, like all electric utilities, sells on the wholesale market generation not needed to meet immediate retail load. The margins from these sales are credited back to ratepayers and reduce the revenue deficiency. When retail sales increase, wholesale margins decrease, and vice versa. The Stipulation and Settlement includes in test-year revenues \$37,700,000 in wholesale margins.

### **2. The RUD-OAG's Claims**

The RUD-OAG challenged this treatment of wholesale margins, questioning whether the accounting mechanisms in place can ever fully capture the costs of maintaining unneeded generating facilities and selling their output at wholesale. The Division suggested eliminating wholesale revenues and excess capacity costs from the ratemaking equation and treating the Company's wholesale operations as an unregulated business.

### **3. The Recommendation of the Administrative Law Judge**

The ALJ rejected the proposal to spin off wholesale operations as an unregulated business, finding that there was no evidence or analysis in the record supporting the claim that the level of wholesale margins incorporated into the test year failed to adequately compensate ratepayers for the costs associated with wholesale sales.

### **4. Commission Action**

The Commission concurs with the Administrative Law Judge's findings, analysis, and recommendations.

While there may be alternative ways to account for wholesale costs and revenues, there is no basis in this record for making even preliminary judgments about the appropriateness of changing the current approach to wholesale margins. Further, the Commission concurs with the Administrative Law Judge that the test-year wholesale margins agreed to by the parties are reasonable and supported by substantial record evidence.

## **D. Jurisdictional Cost Allocations**

### **1. Introduction**

The Stipulation and Settlement accepts the Company's cost allocations between its retail and wholesale operations; no party but the RUD-OAG challenged these cost allocations at any point in the proceeding.

### **2. The RUD-OAG's Claims**

The RUD-OAG claimed that the parties did not have adequate time to examine the Company's cost allocation figures and that the higher rate of return assigned to the wholesale jurisdiction demonstrates that the Company is over-attributing costs to the retail jurisdiction. The rate of

return built into wholesale cost calculations is set by the Federal Energy Regulation Commission, which regulates wholesale energy sales.

### **3. The Recommendation of the Administrative Law Judge**

The ALJ rejected the claim that the parties did not have time to analyze the Company's jurisdictional cost allocations, noting that no other party raised the issue and all agreed to the cost allocations claimed by the Company. She found that it was speculative to attribute the higher rate of return earned at the wholesale level to misallocation of costs and found the jurisdictional allocations accepted in the Stipulation and Settlement fair and reasonable.

### **4. Commission Action**

The Commission concurs with the findings, conclusions, and recommendations of the ALJ.

There is nothing in the record to support the claim that the parties were denied an adequate opportunity to examine the Company's jurisdictional cost allocations. The issue was not the subject of voluminous evidentiary development, but that is logical, given the fact that it was not a contentious issue for any party other than the RUD-OAG.

Nor is there any factual support for the claim that the Company's higher wholesale rate of return must stem from a misallocation of costs. As the Company points out, that rate of return is set by a different regulatory agency, the Federal Energy Regulatory Commission, and is reviewed and adjusted annually based on a formula adopted by that commission.

For all these reasons, the Commission concurs with the ALJ that jurisdictional cost allocations accepted in the Stipulation and Settlement are fair and reasonable.

## **E. The Cost of Variable-Rate Debt**

### **1. Introduction**

The Stipulation and Settlement set the cost of long-term variable debt at 1%, the rate initially recommended by the Large Power Intervenors. The other rates proposed and examined on the record were .59%, proposed by the RUD-OAG; .82%, proposed by the OES; and 2.67%, proposed by the Company.

### **2. The RUD-OAG's Claims**

The RUD-OAG opposed the 1% variable debt rate as unreasonably high and recommended that it be set either at the .59% the Division proposed or at the 2010 "actual rate," which would have to be based on rates in effect before the end of that year.

### **3. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the 1% rate was fair, reasonable, and supported by the record. She recommended accepting the Stipulation and Settlement's provisions on the cost of variable-rate debt.

### **4. Commission Action**

The Commission concurs with the findings, conclusions, and recommendations of the Administrative Law Judge.

As the parties noted, the recent financial crisis and the remedial actions taken in response by the Federal Reserve Board have further complicated the always complex process of setting the test year cost of variable-rate debt. There is no clearly correct number; the goal is to exercise the best judgment possible and to arrive at a fair and reasonable number located within the zone of reasonableness and supported by substantial record evidence.

The 1% number clearly meets these requirements, and it carries the additional credibility of being a mid-range number supported by nearly every party. The Commission concurs with the Administrative Law Judge that the Stipulation and Settlement should be accepted as to the cost of variable-rate debt.

## **F. Margin Impact Analysis Filing Requirement**

### **1. Introduction**

The Stipulation and Settlement also contained provisions that, in brief, (a) obligated Minnesota Power to file a "Margin Impact Analysis" detailing the financial impact of each future significant increase in its Large Power load; (b) permitted any party to the Stipulation and Settlement to petition the Commission for an across-the-board retail rate adjustment based on that increase; and (c) prohibited any party to the Stipulation and Settlement from opposing that petition on grounds that the relief sought constituted prohibited single-issue ratemaking.

The same section of the Stipulation and Settlement also prohibited Minnesota Power from filing a new rate case based solely on loss of Large Power load unless the loss equaled 10% for more than a year, unless total customer nominations fell below 596 MW for more than a year, or unless there was a shutdown or closure of a Large Power customer.

The settling parties explained that these provisions were designed to provide rate stability and give ratepayers the financial benefit of major increases in Large Power load without the delay and expense of a general rate case.

## **2. The RUD-OAG's Claims**

The RUD-OAG opposed these provisions of the Stipulation and Settlement on grounds that the rate adjustment process they described would constitute impermissible single-issue ratemaking. The Division also argued that the settlement provisions appearing to limit the right to file rate adjustment petitions to the settling parties violated the preferential rate prohibitions of Minn. Stat. § 216B.07 and fundamental principles of due process.

## **3. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge recommended approving the provisions of the Stipulation and Settlement relating to Margin Impact Analysis filings, finding them fair and reasonable and not binding on anyone but the settling parties.

## **4. Commission Action**

The Commission will adopt the recommendation of the Administrative Law Judge and accept the provisions of the Stipulation and Settlement relating to Margin Impact Analysis filings.

These provisions do not bind the Commission or anyone other than the settling parties. Essentially, they impose disclosure and filing requirements on the Company, permit other settling parties to file rate-adjustment petitions based on the information disclosed, and bind all settling parties not to raise one specific legal objection – single-issue ratemaking – to those petitions. They do not obligate the Commission to take any specific action on the filings or on any petitions based on them.

The question whether any petition filed under these provisions would constitute a petition for impermissible single-issue ratemaking is not currently before the Commission, and the Commission makes no determination on that issue in accepting these settlement provisions.

Finally, the Commission will clarify that any person or party that may participate in a rate case may file a rate-adjustment petition under the same terms and conditions applicable to the settling parties. It is not clear that the settling parties intended to limit that right to themselves – the Company's reply brief states that they did not,<sup>11</sup> and the Administrative Law Judge explicitly found that the Stipulation and Settlement would not prevent the RUD-OAG from filing a rate adjustment petition.<sup>12</sup> Still, it is important to clarify that point, since the Commission concurs with the RUD-OAG that the public interest is served by encouraging the broadest possible participation in any case potentially affecting retail rates.

For all these reasons, the Commission concurs with the Administrative Law Judge and will accept these provisions of the Stipulation and Settlement.

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<sup>11</sup> Minnesota Power Reply Brief at 6.

<sup>12</sup> ALJ Report, ¶ 76.

## **G. The Stipulation and Settlement as a Whole**

Not only does the Commission concur with the Administrative Law Judge that the RUD-OAG's claims do not require rejecting the Multi-Party Stipulation and Settlement, the Commission concurs that the Stipulation and Settlement as a whole is supported by substantial evidence and in the public interest. It will be approved, as explained below.

### **1. The Legal Standard**

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.<sup>13</sup> Any doubt as to reasonableness is to be resolved in favor of the consumer.<sup>14</sup>

The Act also encourages settlements. Before beginning contested case proceedings on a general rate case, Administrative Law Judges are required to convene a settlement conference for the purpose of encouraging settlement of some or all of the issues in the case. They are authorized to reconvene the settlement conference at any point before the case is returned to the Commission, at their own discretion or at the request of any party.<sup>15</sup>

The Commission is authorized to accept, reject, or modify any settlement. It can accept a settlement only upon finding that to do so is in the public interest and is supported by substantial evidence.<sup>16</sup>

### **2. Factors in Evaluating Settlements**

While the Commission recognizes that compromise is a key ingredient of any settlement, it also recognizes that resolving disputed issues in rate cases is fundamentally different from resolving disputes between private litigants. As the Commission has explained on numerous occasions:

In deciding whether to accept the Offer of Settlement, the Commission must apply a different standard than is normally used by the courts. Unlike the traditional function of civil courts, the Commission's primary function is not to resolve disputes between litigants. Instead, it is an affirmative duty to protect the public interest by ensuring just and reasonable rates.<sup>17</sup>

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<sup>13</sup> Minn. Stat. § 216B.16, subd. 4.

<sup>14</sup> Minn. Stat. § 216B.03.

<sup>15</sup> Minn. Stat. § 216B.16, subd. 1a (a).

<sup>16</sup> Minn. Stat. § 216B.16, subd. 1a (b).

<sup>17</sup> *In the Matter of a Petition by the U.S. Department of Defense, the General Services Administration, and All Other Federal Executive Agencies of the United States Challenging the Reasonableness of the Rates Charged by Northwestern Bell Telephone Company*, Docket No. P-421/CI-86-354, Order Accepting Offer of Settlement (February 10, 1988), at 3.

Because rate case decisions can have far-reaching consequences for persons who were not at the negotiating table, the Commission has long required settling parties to document that all issues have been settled within the zone of regulatory reasonableness:

In non-ratemaking settlement negotiations it is common for parties to concede some issues to obtain a more favorable resolution of others they value more highly. This is reasonable and appropriate in private disputes, where the goal of the settlement process is to reach a result satisfactory to all parties. In Commission proceedings, however, the goal of the process is to serve the public interest.

This requires protecting the interests of the Company, the public, and all customer classes, whether or not their interests are vigorously represented. It requires resolving every issue within the bounds of acceptable regulatory practice, since future rate structures are built on the foundations established in past rate cases. For these reasons the Commission scrutinizes settlements with care and requires documentation of the reasonableness of the disposition of all issues.<sup>18</sup>

### **3. Commission Action**

The Commission finds that the Multi-Party Stipulation and Settlement is supported by substantial evidence, is in the public interest, and should be approved.

The Stipulation and Settlement cites to record evidence to support and explain its disposition of every issue, and all issues were fully developed on the record. The Commission concurs with the settling parties and the Administrative Law Judge that all issues have been settled within the zone of regulatory reasonableness, in a manner supported by substantial evidence, and on terms consistent with the public interest. The Multi-Party Stipulation and Settlement will therefore be approved.

## **H. Construction Work in Progress for Square Butte Transmission Line**

### **1. Introduction**

The Company's original filing misstated the purchase price added to rate base for its newly acquired Square Butte transmission line – a direct-current line running from Center, North Dakota to Duluth – and also erroneously stated that that purchase price included the \$2,890,000 in Construction Work in Progress (CWIP) attributable to the line. The OES spotted these errors, and the Company corrected them on rebuttal, reducing the purchase price to the correct one, which did not include CWIP, and adding the \$2,890,000 in CWIP to its test-year, rate-base CWIP schedules.

When the OES examined the revised figures on rebuttal, however, the agency concluded that tracing the CWIP for the Square Butte line was not a completely straightforward task and stated that it was unable to determine to an adequate level of certainty that the Square Butte CWIP had

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<sup>18</sup> *In the Matter of the Application of Interstate Power Company for Authority to Change its Rates for Natural Gas Service in the State of Minnesota*, Docket No.G-001/GR-90-700, Order Accepting and Adopting Stipulation and Offer of Settlement (June 27, 1991), at 6-7.

not been double-counted. Further, its testimony on the issue was due in nine business days, too short a time to draft, serve, and receive and review answers to information requests designed to clarify the issue.

At hearing, the Administrative Law Judge offered the OES additional time to develop the issue, but the agency declined, citing workload constraints and utilities' obligations to prove up their cases without agency assistance.

## **2. The Positions of the Parties**

The OES argued that it was prejudiced by the Company's late filing of its CWIP figures and that the Company had failed to meet its burden of proof. The agency recommended denying rate recovery of the \$2,890,000 in claimed CWIP expense, without denying the right to request the CWIP in future rate cases.

The Company claimed that the OES was treating a drafting error as a substantive issue and that the record was clear that Square Butte CWIP was not included in any other rate-base CWIP schedule.

## **3. The Recommendation of the Administrative Law Judge**

The ALJ found that the Square Butte CWIP was clearly not double-counted, pointing out that the Square Butte line's project number does not appear in the CWIP schedules originally filed and that the uncontested amount of CWIP attributable to Square Butte – \$2,890,000 – exceeds the entire amount of transmission CWIP in those original schedules.

The ALJ also found that the Company had not delayed in providing its figures on Square Butte CWIP and that the figures provided on rebuttal corrected an obvious error. The ALJ concluded that the OES was not prejudiced in its ability to develop the CWIP issue, especially given the ALJ's offer of additional time to examine the facts.

## **4. Commission Action**

The Commission concurs with the findings, conclusions, and recommendation of the Administrative Law Judge.

The Company's original belief that Square Butte CWIP was accounted for in the purchase price was clearly mistaken – as the OES pointed out – and the CWIP schedules the Company filed to correct that error were straightforward. Those schedules accounted for the \$2,890,000 in CWIP that was previously unaccounted for.

Furthermore, no party has pointed to anything in those schedules or elsewhere in the record suggesting that the Square Butte CWIP has been double-counted or otherwise misrepresented. As the ALJ notes, without the addition of the Square Butte CWIP, the Company's transmission CWIP schedules show lower amounts of CWIP than the \$2,890,000 in CWIP attributable to Square Butte alone. The Company has proved by a preponderance of the evidence that the revised CWIP schedules showing the \$2,890,000 in Square Butte CWIP are accurate and that the Square Butte CWIP is recoverable in rates.

The Commission also concurs with the Administrative Law Judge that the OES was not prejudiced in its ability to develop this issue, believing that the ALJ managing the development of the record and presiding over the evidentiary hearings is in the best position to make such procedural judgments.

For all these reasons, the Commission will approve the inclusion of the Square Butte CWIP in test-year rate base.

## **VI. Boswell 4 Capital Investments**

### **A. Introduction**

The test year rate base proposed by the Company included some \$75,750,784 in capital improvements to its largest generating unit, Boswell 4, which is a coal-fired unit. The Company explained that 2010 was a regularly scheduled outage year for the plant and that it intended to take the opportunity to upgrade specific plant components besides performing the major repairs, replacements, and maintenance tasks normally performed in outage years.

In addition to adding and replacing burners and ignition equipment to reduce nitrogen oxide emissions, retubing the steam condenser, and upgrading the air heater and flue path expansion joints, the Company planned four major efficiency improvement projects:

- Replacing the plant's 30-year-old turbine with a new high-efficiency turbine.
- Re-engineering the boiler surface to end problems with overheating and re-heating.
- Replacing existing ash-removal devices to permit the use of coal with higher percentages of slagging materials.
- Replacing existing cooling tower motors with higher horsepower units, modifying the closed cooling water system to increase its efficiency, and replacing high-pressure feed-water heaters and drip pumps to reflect actual flow rates.

### **B. Positions of the Parties**

#### **1. Joint Intervenors**

The Joint Intervenors<sup>19</sup> challenged the inclusion of these investments in rate base, claiming that they went beyond prudent maintenance and upkeep and should be disallowed without detailed analysis demonstrating that they would still be economically justified once the federal government began regulating greenhouse gases and coal combustion residue, which they considered imminent.

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<sup>19</sup> The "Joint Intervenors" are the Izaak Walton League of America – Midwest Office, Fresh Energy, and the Minnesota Center for Environmental Advocacy.

The Joint Intervenors emphasized that the Company's filing disclosed that the capital investments would increase the useful life of Boswell 4 by seven years – from 2028 to 2035 – and argued that this was further evidence that the Company was expanding its dependence on coal, at great risk to ratepayers, without seeking Commission authorization of that strategy.

## **2. The Company**

The Company stated that these investments were required to reduce the emissions, improve the efficiency, and maintain the reliability of its largest generating unit, which has long been an economical and reliable source of base-load power. The seven-year life extension, the Company said, is an incidental byproduct of these investments and is relevant mainly for depreciation and accounting purposes – it was not the goal of the investments and does not obligate the Company to operate the plant for an additional seven years. These investments were in the nature of routine maintenance and were made to permit the plant to fulfill its originally intended duty cycle.

While the Company is engaged in adding substantial amounts of renewable generation to its system over the next several years, it argued that the best available information indicates that it will still need this relatively inexpensive and environmentally compliant base-load generation well into the future. The Company stated that the costs of possible future regulation of greenhouse gases and coal residue would best be monitored, examined, and dealt with on a real-time basis.

### **C. The Recommendation of the Administrative Law Judge**

The ALJ found that the Joint Intervenors' arguments about the economic impact of possible future federal regulation of greenhouse gases and coal combustion residue were speculative. She concluded that "[t]he record reflects that these are maintenance projects intended to keep the facility functioning and environmentally compliant until the end of its service life. . . ." <sup>20</sup>

She recommended including the Boswell 4 capital investments in rate base for rate recovery.

### **D. Commission Action**

The Commission concurs with the findings, conclusions, and recommendation of the Administrative Law Judge.

These capital investments do not rise to the level of a refurbishing or a retrofitting, and they are not intended to extend the life of the plant. They are major maintenance, repair, and replacement projects that must be done to reduce the emissions, improve the efficiency, and maintain the reliability of this large, low-cost, base-load unit to the end of its existing life cycle. These investments, made under these circumstances, do not compel the exhaustive economic analysis required of a new or refurbished resource.

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<sup>20</sup> ALJ Report, ¶ 192.

## **VII. Pension Costs**

### **A. Introduction**

For the past three years the Company has determined the pension costs reported in its public financial statements by selecting a discount rate for its future pension liabilities from a range of discount rates prepared by its actuarial firm. The actuarial firm develops its range of discount rates by conducting a Yield Curve Analysis incorporating the specific characteristics of the Company's pension plan and applying the results of that analysis to the Citigroup Pension Discount Curve in effect on December 31 of the reporting year.

The Company used the same method to determine test-year pension expense in this rate case. Its initial filing set test-year pension expense at \$1,968,355, based on its projection of a 6.75% year-end pension discount rate. Its rebuttal filing raised pension expense by 41% -- to \$2,768,866 -- based on the actual year-end pension discount rate selected, 5.81%.

### **B. Positions of the Parties**

#### **1. The OES**

The OES challenged the reasonableness of the Company's test-year pension expense mainly on grounds that the pension discount rate in effect at any single point in time from *any* source is not an adequate basis for setting pension costs for ratemaking purposes. The OES did not challenge the use of the Company's method for financial reporting purposes.

The OES pointed out that the Company's actual pension costs had varied widely over the past five years, as set forth below:

2005	\$2,718,437
2006	\$4,299,082
2007	\$ 457,165
2008	\$ (554,057)
2009	\$ 293,312

The agency argued that the most effective means of neutralizing this volatility and arriving at a reasonable estimate of the Company's annual costs over the next few years -- when the rates set in this case will be in effect -- was to use the Company's five-year historical-average pension expense. The agency pointed out that averaging costs over time is a ratemaking tool commonly used to protect ratepayers and shareholders from the effects of test-year anomalies or the risks associated with extremely volatile costs or revenues.

The Company's average annual pension costs were \$1,442,778 for calendar years 2005 through 2009 and \$1,452,891 for calendar years 2006 through 2010. The OES argued that the negligible difference between the average costs for these two time periods (\$10,103) -- compared to the 41%, \$800,531 difference between the Company's initial and rebuttal cost estimates -- was further evidence of the fundamental reasonableness of the averaging approach.

## **2. The Company**

The Company argued that its method of forecasting pension costs was transparent, methodologically sound, and free of bias.

The Company emphasized that its discretion in selecting a discount rate was severely limited by its reliance on the Citigroup Pension Discount Curve, its need to select a discount rate from the range prepared by its actuarial firm, and its need to conform to its independent auditor's understanding of reasonable business and accounting practices.

The Company pointed out that its method of forecasting pension costs was accepted within the larger business community and that the Commission had accepted pension cost forecasts based on actuarial assumptions in other rate cases.

### **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the Company's methodology for forecasting pension expense was reasonable and consistent with the generally accepted accounting principles all publicly traded companies must use. The ALJ found no evidence that the Company had manipulated the pension discount rate to the disadvantage of ratepayers or had selected an unusually volatile index for establishing pension expense.

The ALJ found that the Company's actuary, in accordance with generally applicable accounting rules, phased in pension asset gains and losses over five years, and that further normalization or averaging was unnecessary. The ALJ recommended approving the Company's revised test-year pension expense.

### **D. Commission Action**

The Commission respectfully declines to accept the recommendation of the ALJ on this issue, not because the Commission doubts the Company's good-faith adherence to its chosen methodology, but because that methodology is too narrow to support a finding of just and reasonable rates.

The Commission concurs with the OES that it is not prudent or reasonable to base a significant component of test year costs – and the resulting retail rates – on the pension discount rate in effect for a single point in time from *any* source. Between June 2008 and March 2010, the Citigroup pension discount rate ranged from 8.01 to 5.54.<sup>21</sup> Between the Company's selection of its year-end discount rate and March 2010, the Citigroup Pension Discount Curve has been trending upward.<sup>22</sup> Building millions of dollars into rates on the basis of where a fluctuating pension discount rate rests on a given day – without record evidence demonstrating that the discount rate on that day is uniquely probative and reliable for forecasting test-year pension expense – is neither reasonable nor prudent.

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<sup>21</sup> Initial Brief, Office of Energy Security, at 39.

<sup>22</sup> Initial Brief, Office of Energy Security, at 39-40.

In past rate cases the Commission has emphasized that the goal in ratemaking is to reflect actual costs as accurately as possible, making it important to find the most accurate cost-measurement tools available. Which tools are the most accurate is a fact-specific inquiry, and the answers vary from case to case. In this case, actual historical experience appears to be a more trustworthy basis for determining test-year pension costs than a highly volatile pension discount rate, especially when the predictive power of that rate is limited by treating its position on a single day as definitive.

For all these reasons, the Commission will set test-year pension expense at \$1,452,891, the Company's average annual pension costs for calendar years 2006 through 2010.

## **VIII. Other Post-Employment Benefits**

### **A. Introduction**

Minnesota Power's initial rate case filing included \$6,216,000 in test-year expense for post-employment benefits other than pensions. These benefits are commonly called OPEB (other post-employment benefits), and mainly consist of health insurance for retirees. In its rebuttal filing, the Company increased this test-year expense by 23%, to \$7,659,338, due mainly to the same increase in the pension discount rate discussed above in relation to pension costs.

Through inadvertence, the Company did not give the OES and other parties timely notice that it intended to seek this increase. (Because of the volume and complexity of the financial information filed in every rate case – and the tight statutory time constraints under which it must be analyzed – companies and the OES are typically in constant conversation about anticipated changes in the financial information in the case.)

Instead of being disclosed directly, the information was misplaced in a supplemental response to an unrelated discovery request, with no indication that the Company intended to revise its initial filing to request rate recovery of the increase. When the Company requested this additional \$1,443,317 on rebuttal, the OES was taken by surprise and did not have time to conduct the discovery, auditing, and analysis required to confirm the accuracy, reasonableness, and prudence of the request.

The OES filed a motion to strike the testimony, which was denied. The ALJ did offer the OES additional time to respond to the revised figures, but the agency stated that it could not adequately analyze the request without a waiver of the statutory rate-case deadline, which the Company declined to grant.

### **B. Positions of the Parties**

#### **1. The OES**

The OES opposed the 23% increase both on grounds that it was unreasonable to base an increase of this magnitude on a pension discount rate from a single source at a single point in time – the same grounds discussed in detail in its challenge to the revised test-year pension expense – and on grounds that the revised numbers could not be adequately audited and analyzed at this point in the case.

## 2. The Company

The Company defended its reliance on the December 31, 2009 pension discount rate on the same grounds relied upon in its discussion of its test-year pension costs and pointed to the ALJ's denial of the OES motion to strike as dispositive on the OES's claim that it had been denied an opportunity to properly vet the numbers submitted in the Company's rebuttal filing.

### C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended denying rate recovery of the OPEB increase sought by the Company on grounds that the OES had been prejudiced in its ability to develop the issue by the Company's failure to timely disclose its intention to seek the increase. She recommended granting rate recovery of the test-year expense in the initial filing, \$6,216,000, a figure audited and analyzed by the OES and uncontested by any party.

### D. Commission Action

The Commission concurs with the recommendation of the Administrative Law Judge.

The OES, the one party charged by statute with representing the broad public interest in this case, did not have a meaningful opportunity to examine, audit, and analyze the Company's claim to this additional \$1,443,317. The agency explained that, had it known of this claim, it would have obtained the Company's work papers and related documents through discovery, audited and analyzed all information provided, and possibly retained an independent actuary to analyze any remaining questions.<sup>23</sup>

As it is, the agency is unable to determine even that the Company's numbers are correct, let alone its underlying assumptions and resulting calculations. Without adequate time to obtain and examine the bridging schedules and other documents linking new costs to those originally claimed (and fully vetted by the OES), the agency cannot make a judgment on their accuracy.

The Commission concurs with the ALJ that it cannot include these costs – which are essentially raw, unaudited, and unsubstantiated – in rates. The Company has the burden of proof, and any doubt as to reasonableness must be resolved in favor of the consumer.<sup>24</sup> These costs, which have not been through standard rate-case auditing and verification procedures, do not meet the standard of reasonableness.

Finally, the Commission notes that these costs may also fail the test of reasonableness for the same reason that increased pension costs failed, their dependence upon a single, highly volatile pension discount rate on a single day. However, that issue, too, has not been adequately developed in the record, and will not be resolved here.

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<sup>23</sup> Initial Brief of the Office of Energy Security, p. 58.

<sup>24</sup> Minn. Stat. 2216B.03.

## **IX. Incentive Compensation**

### **A. Introduction**

After its last rate case, the Company stopped offering incentive compensation to the vast majority of its employees, instead raising their base compensation. The Company continued to offer incentive compensation only to high-level management employees, including 89 employees enrolled in its Annual Incentive Plan.

The Annual Incentive Plan, which was approved as a test-year expense in the Company's last rate case, provides performance-based compensation of up to 20% of base salary to 89 high-level management employees. The Company sought to increase test-year expense for this program from \$868,182 to \$1,681, 186, stating that it was important to maintain a clear link between performance and salary for these key employees.

The Company explained that the test-year increase in this program was mainly due to shifting some of the expense of the discontinued company-wide incentive program to this program, since the Company had determined it preferred to compensate these employees on a performance basis instead of granting them the base salary increases the rest of the workforce received in 2009 and 2010. Total company-wide incentive compensation expense would remain some \$2,000,000 below what was approved in the last rate case.

The Company also proposed to continue deferring and tracking all unpaid test-year incentive compensation amounts for future refunding to ratepayers.

### **B. Positions of the Parties**

#### **1. The RUD-OAG**

The RUD-OAG opposed including any incentive compensation in test-year expense, arguing that incentive compensation was unnecessary to attract and retain highly qualified management personnel in the current economic climate.

The Division also emphasized that incentive compensation was not equally distributed among the 89 eligible employees, with the top ten recipients receiving average annual incentive compensation of some \$55,000. The Division argued that it would be more appropriate for the Company's shareholders to bear the cost of bonuses of this magnitude, especially during the current economic downturn.

#### **2. The Company**

The Company emphasized that total test-year incentive compensation expense was \$2,000,000 below levels authorized in the last rate case and that employees eligible for incentive compensation had not and would not receive the base salary increases granted to other employees.

The Company stated that it continued to believe that the compensation of key decision-making personnel should be linked to performance and that incentive compensation was an important component of a performance system designed to attract and retain top-quality personnel at the highest levels of responsibility.

### **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the Company's test-year incentive compensation expense was reasonable, was consistent with the Commission's determinations in the last rate case, and should be approved.

### **D. Commission Action**

The Commission concurs with the Administrative Law Judge and will approve the Company's test-year incentive compensation expense, subject to the continuing requirement that the Company track and refund to ratepayers unpaid amounts of incentive compensation recovered in rates.

The amounts at issue are significantly lower than those approved in the last rate case, and there is no evidence in the record that total compensation levels for the Company's key management employees are excessive or inconsistent with industry norms. Nor, importantly, is there any evidence in the record that the incentives built into the compensation scheme are misaligned with ratepayer interests, a concern in the last rate case.

Barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment. For all these reasons, the Commission will approve the Company's proposed incentive compensation test-year expense.

## **X. Employee and Board Expenses Other than Salary and Benefits**

### **A. Introduction**

The Company claimed \$1,841,000 in test-year expense for employee and Board member expenses other than salary and benefits. These expenses include travel, lodging, meals, entertainment, employee recognition awards, and similar items. The Company arrived at this figure by working from its 2008 employee and Board expenses – due to the economic downturn, its 2009 expenses were at a substantially lower level than the Company considered unsustainable.

The Company's original test-year budget for Board and employee expense was \$2,355,000. From this amount it subtracted 100% of expenses for its top six executives and one executive assistant, and 25% of expenses for the other six company officers. It also excluded 100% of its dues to two country clubs and excluded all Board expenses except for compensation and travel to one annual Board meeting. These exclusions totaled \$514,000, approximately 21% of amounts initially budgeted.

## **B. Positions of the Parties**

### **1. The RUD-OAG**

The RUD-OAG conducted a detailed review of the Company's 2008 and 2009 Board and employee expenses and challenged scores of individual expenditures, including expenditures for meals; lodging; travel; entertainment; employee recognition gifts; department parties; and gifts, cards, and flowers to mark employee accomplishments or life-events.

The Division reviewed a sample of statements for Company credit cards held by Board members and employees and concluded that 70% of the charges made by Board members and 7% of those made by employees were unreasonable, imprudent, or not reasonably related to the provision of utility service. The Division also concluded that the Company had spent \$506,541 on employee recognition events and gifts,<sup>25</sup> an amount it argued was exorbitant for a company that has approximately 1,250 employees.

The RUD-OAG recommended three major disallowances, totaling approximately \$1,300,000. First, the Division recommended disallowing either 100% of non-salary and benefit expenses for the Company's top 12 executives (instead of the six recommended by the Company), three additional vice presidents, and the executive assistant or disallowing 70% of their credit card charges.

Second, the RUD-OAG recommended disallowing 7% of all charges on employee-held Company charge cards. The Division acknowledged that this was an imprecise remedy, since total credit card charges totaled \$11,200,000, far in excess of total employee expenses. Further, these charges included some executive expenses that would be eliminated under the first recommended disallowance, included some operating and maintenance expenses that were not at issue, and included some employee recognition expenses, which would be eliminated under its third recommended disallowance.

Third, the Division recommended disallowing all amounts spent on employee recognition. The Division also recommended requiring the Company to develop an Employee Expense Compliance Plan similar to that adopted by Xcel Energy in its last rate case to provide greater clarity in future rate cases.

### **2. Minnesota Power**

The Company claimed that all amounts remaining in Board and employee test-year expense after its original deductions were reasonable and necessary utility expenses. The Company emphasized the importance of a favorable work environment for work quality and employee productivity.

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<sup>25</sup> The Company later stated that this was a total Company amount, rather than a Minnesota jurisdictional amount, and that the Minnesota jurisdictional amount was \$405,793.

The Company explained that its employee recognition budget included nearly \$60,000 in safety incentive expenses and that employees holding Company credit cards used them for specific operating and maintenance expenses as well as employee expenses. The Company also clarified that some meals included in employee expense were “overtime meals” mandated under its collective bargaining agreements.

### **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the record on Board and employee expenses made precision impossible. The Company did not account for all Board and employee expenses in one place, had no system for itemizing expenses by type, and had no written policies on what types of expenses were rate-recoverable and how they should be documented.

She found that neither the Company nor the RUD-OAG had adequately addressed the issue. She concluded that the Company’s method of categorical exclusion was clearer and easier to follow, but that it had no persuasive analytical or factual basis. She also found that it understated the amount of Board and employee expense that must be excluded from test-year expense. On the other hand, she found that there were serious problems with some of the RUD-OAG’s numbers.

She concurred with the Company that many of the Division’s numbers were not limited to the Minnesota jurisdiction, but were based on total Company costs. Similarly, she found that at least some \$5,200,000 of the \$11,200,000 in employee credit card charges were for materials procurement, \$1,500,000 were for charges billed to affiliates, and \$900,000 were for phone and data services, making a remedy based on credit card charges problematic. She also disagreed with the Division’s conclusions on some specific expenses, such as those connected with the dedication of the Company’s Taconite Ridge wind farm.

More important, she found that the RUD-OAG’s “proposed exclusions based on credit card statements are not reliably calculated,”<sup>26</sup> due to timing discrepancies that led to significant overlap and double-counting.

Still, she concluded that the RUD-OAG’s arguments were essentially meritorious, pointing out that the dramatic drop in Board and employee expenses in 2009 caused by the economic downturn demonstrated that these expenses were much more discretionary than many other utility expenses. And she found that \$1.84 million in discretionary Board and employee expenses was a large number for a company with approximately 1,250 employees.<sup>27</sup>

She also found that the RUD-OAG had identified specific expenditures – for example, restaurant and catered meals, gift cards, floral arrangements, travel for employees’ family members – that clearly should not be charged to ratepayers. And she disagreed with the Division on the rate-recoverability of other individual expenditures, such as meals at conferences and working lunches. Overall, she stated that the major challenge was the absence of Company policies on treating individual expenses as rate-recoverable and the absence of accounting procedures permitting their examination.

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<sup>26</sup> ALJ Report, ¶ 241.

<sup>27</sup> ALJ Report, ¶ 244.

She concluded that an adjustment to test year expense was necessary to ensure just and reasonable rates and that building on the RUD-OAG's recommendations was the best option. She recommended two adjustments to test-year expense: (1) disallowing test-year employee expense for the Company's top twelve executives and two additional vice-presidents, an adjustment totaling \$190,237; and (2) disallowing all employee recognition expenses minus employee safety incentives, an adjustment totaling \$355,022.

She acknowledged that these numbers were not perfect, but found that without them the Company's test year expense could not be found just and reasonable.

To ensure greater accuracy in the future, she also recommended requiring the Company, in future rate cases, to include and itemize employee recognition expenses within the travel, entertainment, and related employee expenses it is required to list and document under Minn. Stat. § 216B.16, subd. 17. She further recommended requiring the Company to develop written policies on the inclusion in test-year expense of employee travel, lodging, and meals and to implement an employee expense compliance plan to ensure that those policies are followed.

#### **D. Commission Action**

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations on this issue.

The Company has the burden of proof in this case and must prove the accuracy, reasonableness, and eligibility for rate recovery of every component of test-year expense by a preponderance of the evidence. Any doubt as to reasonableness must be resolved in favor of the consumer.<sup>28</sup> Here there is substantial doubt that it is reasonable, prudent, and necessary for the provision of utility service for Minnesota Power to spend \$1,841,000 on an annual basis for Board and employee expenses.

First, the Company did not spend anything approaching that amount in 2009, when it was experiencing the worst effects of the economic downturn. While the total amount of 2009 Board and employee expense is not in the record, the Administrative Law Judge noted that the fragmentary information in the record showed that 2009 credit card charges fell to \$8,600,000 from the previous year's \$11,200,000 and that the expense levels of some executives fell from 20% to 50% of 2008 levels.

Though it might not be reasonable to expect the Company to operate forever at the level of austerity required in 2009, it is clear, as the ALJ noted, that these expenses are more discretionary than many others and therefore require closer scrutiny.

Second, the Company has no clearly articulated standards for determining which Board and employee expenses are rate-recoverable, which intensifies already legitimate concerns about their discretionary nature. (In fact, the only specific expense category it treated as non-rate-recoverable – and stated this was only to avoid the cost and expense of rate-case litigation – was country club dues.) Nor does the Company have in place accounting practices and

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<sup>28</sup> Minn. Stat. § 216B.03, 216B.16, subd. 4.

procedures that isolate these costs and render them transparent and auditable. In short, the Company's policies and practices make it extremely difficult to confirm the accuracy, legitimacy, purpose, and reasonableness of these expenses.

Finally, the Commission concurs with the Administrative Law Judge that numbers this large, for expenses this discretionary, for purposes essentially unarticulated and analyzed, cannot be built into rates. As the ALJ notes, the Company has only 1,250 employees, and therefore, annual employee recognition expenses of \$355,022 and annual Board and employee expenses of \$1,841,000 require itemization, explanation, and justification.

For all these reasons, the Commission will adopt the disallowances recommended by the Administrative Law Judge, agreeing that, while they are imprecise, they are the best the record allows. The Commission cannot include in rates expenses that have not been shown, by substantial evidence in the record, to be reasonable, prudent, and necessary for the provision of utility service. With the adjustments adopted here, the Company's Board and employee expense test-year amount meets that standard.

To ensure greater clarity in the future, the Commission will require the Company, in future rate cases, to include and itemize employee recognition expenses within the travel, entertainment, and related employee expenses it is required to list and document under Minn. Stat. § 216B.16, subd. 17. The Commission will also require the Company to develop written policies on the rate-recoverability of employee travel, lodging, and meals and to implement an employee expense compliance plan to ensure that those policies are followed.

## **XI. Aircraft Expense**

### **A. Introduction**

The Company included in test-year expense \$622,051 in aircraft costs. The Company owns and operates a corporate aircraft purchased from an affiliate in a transaction approved by the Commission in 2007.<sup>29</sup> The order approving the purchase required the Company to file a cost/benefit analysis of its aircraft ownership in its next rate case.

In its next rate case, the Company submitted a study that the Commission found fell short of a comprehensive cost/benefit analysis, but found that the study, combined with other evidence in the record, demonstrated the aircraft's value to the utility in providing electric service. The Order granted rate recovery of 50% of the costs of ownership.<sup>30</sup>

In this case, the Company sought rate recovery of approximately 40% of the Minnesota jurisdictional costs of its aircraft ownership, relying on the Commission's recent decision that the value of the aircraft to utility operations justified rate recovery of 50% of its costs.

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<sup>29</sup> *In the Matter of Minnesota Power's Petition for Approval of Aircraft Ownership Transfer Between Allete, Inc. and Adesa, Inc.*, docket no. E-015/PA-06-1589, see order dated March 8, 2007.

<sup>30</sup> *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, docket no. E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order (May 4, 2009).

## **B. Positions of the Parties**

### **1. The RUD-OAG**

The RUD-OAG urged disallowance of 100% of aircraft ownership expenses, claiming the aircraft was unnecessary for the provision of utility service and that the Company had failed to submit a proper cost/benefit analysis that would justify its inclusion in rates.

### **2. Minnesota Power**

The Company argued that its current use of the aircraft did not differ significantly from the use described in the last rate case, which the Commission determined justified rate recovery of 50% of ownership costs. The Company emphasized that commercial air service to and from Duluth was less frequent and convenient than in major metropolitan areas and that aircraft ownership often permitted more efficient use of Company resources than working around commercial air schedules.

## **C. Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that permitting rate recovery of 50% of aircraft expense was consistent with the Commission's May 2009 decision examining essentially the same issue. She recommended including the test-year expense proposed by the Company in rates.

## **D. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendations on this issue.

There is no record evidence that the circumstances that led the Commission to grant 50% rate recovery in the last rate have changed significantly. At that time the Commission concluded that aircraft ownership provided advantages in efficiency and flexibility that benefitted ratepayers, and this record supports the same determination.

The Commission concurs with the RUD-OAG, however, that aircraft expenses bear monitoring and periodic reexamination. That is especially true here, where the cost/benefit analysis submitted in the last rate case was less comprehensive than would be ideal. The Commission will therefore require the Company to file a comprehensive cost/benefit analysis of its ownership of its aircraft in its next rate case.

## **XII. Economic Development Expense**

### **A. Introduction**

The Company sought to include in test-year expense 100% of its economic development expenses, which totaled \$316,131. This amount was less than half of the amount granted rate recovery in its last rate case, where the Commission permitted rate recovery of 50% of its economic development costs. Most of these test-year costs go to local economic development organizations, such as the Area Partnership for Economic Expansion.

## **B. Positions of the Parties**

### **1. Minnesota Power**

Minnesota Power submitted economic studies that it argued demonstrated substantial ratepayer benefit from its economic development activities and pointed out that its economic development program enjoyed wide public support, as demonstrated by the testimony in the public hearings.

The Company claimed that the provision in the Public Utilities Act permitting recovery of economic development costs at the Commission's discretion demonstrated a legislative commitment to utility involvement in economic development.<sup>31</sup> And it emphasized that it was seeking a lower amount of economic development expense in this rate case than had been allowed in its previous rate case, reducing the financial impact of these expenses on ratepayers.

### **2. The OES**

The OES challenged many of the underlying assumptions in the Company's economic studies and the Company's interpretation of their results. The OES argued that economic development costs should be recovered only if they were clearly shown to have produced lower rates for ratepayers – revenues from enterprises that benefitted from development assistance, but may have remained or located in the service area without it, could not be counted or must be significantly discounted.

The OES concluded that the Company had not met the ratepayer benefit test and recommended disallowing all economic development expenses.

### **3. The RUD-OAG**

The RUD-OAG concurred with the OES that the Company's economic studies did not demonstrate economic benefits to ratepayers justifying rate recovery at 100%. The Division argued that shareholders benefit at least as much as ratepayers from successful economic development efforts and should share the expenses equally. The RUD-OAG recommended granting rate recovery of 50% of the Company's economic development expenses.

## **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge recommended rate recovery of 100% of the Company's economic development costs, stating that its economic studies demonstrated that these investments had positive impacts on the Company over a period of 10 to 20 years and that these benefits far outweighed their costs.<sup>32</sup> She also found that the Company had demonstrated that these investments provide some benefit to ratepayers.<sup>33</sup>

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<sup>31</sup> Minn. Stat § 216B,16, subd. 13.

<sup>32</sup> ALJ Report, ¶ 262.

<sup>33</sup> ALJ Report, ¶ 266.

She pointed out that the amount the Company was seeking was lower than the amount allowed in its last rate case and found that the Company could not exercise meaningful economic development leadership without spending at least the amount sought.

#### **D. Commission Action**

The Commission respectfully declines to accept the recommendation of the Administrative Law Judge on this issue. The Company's ability to demonstrate that its economic development investments provide some benefit to ratepayers is not sufficient to ensure 100% rate recovery, nor is the fact that the total amount of test-year expense is lower than it was in its last rate case.

The Public Utilities Act permits, but does not require, the Commission to allow a utility to recover from ratepayers expenses incurred in economic and community development.<sup>34</sup> The Commission has often granted partial recovery of economic development costs, recognizing that these costs generally benefit shareholders as much as ratepayers. The Commission finds that here, too, a 50/50 sharing represents the most equitable distribution of these costs, since both Company and ratepayers benefit from them.

Ratepayers clearly benefit when their communities thrive; to the extent that economic development programs enhance the economic stability and growth of local communities, they serve ratepayers. Similarly, to the extent that economic development programs increase customer numbers or retail load, thereby spreading fixed costs over a larger customer base, they serve ratepayers. It makes sense, then, for ratepayers to share in their costs.

At the same time, shareholders also benefit when the communities they serve thrive. Their overall revenues are higher and more stable. They sustain lower bad debt costs and face lower risks of stranded investment. And they reap substantial public relations benefits within the communities they serve from their economic development investments.

These benefits, on either the ratepayer or shareholder side of the ledger, are not readily quantifiable. But they clearly exist, as is demonstrated by the public testimony supporting Minnesota Power's economic development efforts, the Company's continued commitment to those efforts, and the legislative mandate requiring the Commission to consider granting them rate recovery.

For all these reasons, the Commission will grant Minnesota Power rate recovery of 50% of its proposed test-year economic development expense.

### **XIII. Rate Case Expense**

#### **A. Introduction**

The Company included in test-year expense \$1,996,894 in rate case expenses. This amount included the projected costs of professional services, regulatory assessments, intervenor compensation, and miscellaneous costs.

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<sup>34</sup> Minn. Stat. § 216B.16, subd. 13.

The RUD-OAG recommended denying recovery of 50% of the Company's test-year rate case expense on grounds that the Company had failed to take reasonable measures to control rate case costs, including engaging in competitive bidding for rate case representation.

## **B. Positions of the Parties**

### **1. The RUD-OAG**

The RUD-OAG argued that the Company had not demonstrated serious effort to control its rate case costs and recommended that it be required to engage in competitive bidding before choosing outside counsel in future rate cases. The Division pointed out that Xcel Energy uses competitive bidding in retaining counsel for rate case proceedings.

### **2. The Company**

As evidence that it was making serious efforts to control rate case costs, the Company pointed out that its projected expenses for this rate case were 17% below its actual expenses for its last rate case.

In regard to competitive bidding, the Company emphasized the unique and specialized knowledge required in rate case representation and stated that there were cost and quality advantages to maintaining continuity in its rate case team, including outside counsel. The Company stated it believed it would be more expensive to secure representation through competitive bidding, since new counsel would need more time and resources to become familiar with the facts and issues specific to Minnesota Power.

## **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that there was no factual basis to conclude that Minnesota Power had failed to control rate case costs or that rate case costs should have been lower. She recommended including the proposed test-year expense in rates.

## **D. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendation.

While the Commission concurs with the RUD-OAG on the importance of controlling rate case costs, and is open to new approaches to accomplishing that goal, the rate case expenses proposed for recovery in this case are prudent and reasonable and will be approved.

Finally, because rate case intervals are always uncertain, the Commission will take a step it has taken in other recent rate cases; it will require the Company to track rate case expense recoveries exceeding the authorized test-year expense, for possible crediting against the revenue requirement in the next rate case. This approach both protects ratepayers from over-collection and eliminates any need to consider the rate-case-interval estimate accepted in this case as a factor in determining the timing of the next rate case.

## **XIV. Costs of Defending Enforcement Action by the Environmental Protection Agency**

### **A. Introduction**

The Company included in test-year expense \$250,000 in legal and consulting costs associated with its defense of a Notice and Finding of Violation from the United States Environmental Protection Agency for alleged violations of the Clean Air Act at the Boswell and Laskin generating facilities between 1981 and 2009.

### **B. Positions of the Parties**

The RUD-OAG and the Joint Intervenors<sup>35</sup> urged disallowance of these costs on grounds that the shareholders, not the ratepayers, should bear the costs of the Company's "unlawful activities or claimed violations of law."<sup>36</sup>

The Company stated that it was in full compliance with the law at all relevant times and stated that it is engaged in ongoing discussions with the EPA regarding the Notice and Finding of Violation.

### **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge recommended including the costs in rates on grounds that it was premature to exclude costs associated with defending a pending claim. She noted that if the allegations were admitted or otherwise proven, and a fine resulted, it was likely that the fine should be excluded from rate recovery.

### **D. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendation on this issue.

As Minnesota Power notes, these allegations are unproven and they are denied by the Company. The cost of defending them is clearly an integral part of providing utility service. It would be premature to deny rate recovery at this time, and the Commission will permit rate recovery of these expenses.

## **XV. Charitable Contributions**

### **A. Introduction**

The Company budgeted \$1,295,000 for charitable contributions in the 2010 test-year and proposed rate recovery of 50% of that amount. By statute, the Commission may permit rate recovery of up to 50% of utilities' qualified charitable contributions.<sup>37</sup>

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<sup>35</sup> The Joint Intervenors are the Izaak Walton League of America – Midwest Office, Fresh Energy, and the Minnesota Center for Environmental Advocacy.

<sup>36</sup> Ex. 73 at 27-28 (Lindell Surrebuttal).

<sup>37</sup> Minn. Stat. § 216B.16, subd. 9.

The Company's 2009 actual charitable contributions of \$654,000 were significantly below that amount, as well as significantly below the amount of test-year charitable contributions upon which its rates had been based. The Company explained that it had reduced its charitable contributions in 2009 due to the severe economic downturn, but intended to resume and exceed its pre-downturn charitable giving levels in 2010 and beyond.

## **B. Positions of the Parties**

### **1. The OES and RUD-OAG**

The OES and the RUD-OAG initially recommended granting rate recovery of \$327,000, 50% of the Company's actual 2009 giving levels. These parties argued that actual giving was a more reliable indicator of future giving than stated intentions and emphasized that rate recovery of charitable contributions was discretionary.

The OES later revised its position to recommend rate recovery of \$443,989, 50% of the Company's average annual charitable contributions for 2007 through 2009. The OES stated that it was reasonable to assume the Company would give more in 2010 than 2009, when economic conditions were without recent precedent. The OES also argued that averaging over time would provide a more accurate picture of likely future giving by smoothing out anomalies.

### **2. Minnesota Power**

The Company stated that it intended to give the full amount budgeted for charitable contributions, argued that its charitable giving had steadily increased over time, and that 2009 was an anomaly. The Company pointed out that many, if not most, corporations had reduced charitable giving in 2009.

The Company also argued that its practice of giving through its charitable foundation, the Minnesota Power Foundation, reduces volatility in giving and ensures that it will actually give at budgeted levels.

## **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that the Minnesota Power Foundation had not ensured that 2009 charitable giving met budgeted levels and that the most reasonable course of action was the one proposed by the OES, averaging actual charitable giving for 2007, 2008, and 2009.

## **D. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendation on this issue.

The Commission agrees that using factual data on past charitable giving is the most reliable approach for building projected charitable giving into rates. In 2009 Minnesota Power ratepayers paid \$552,000 toward charitable contributions of \$654,000, despite the statutory provision limiting rate recovery to 50% of charitable contributions. While the economic situation was truly anomalous, charitable contributions were still over-recovered; relying more heavily on factual data than stated intentions is clearly a reasonable strategy for preventing recurrence of over-recovery.

The Commission also agrees that using average annual giving over the three most recent calendar years is a reasonable strategy for smoothing anomalies, whatever their source. A three-year average is likely to have more predictive value than data from a single year, and is especially likely to have more predictive value than the Company's 2009 spending, given the extraordinary financial circumstances of that year.

Finally, while the Minnesota Power Foundation is no doubt an effective vehicle for corporate giving, the Commission concurs with the ALJ that its failure to ensure giving at fully budgeted amounts in 2009 reduces the power of the Company's claim that the Foundation will ensure giving at fully budgeted amounts in the future.

For all these reasons, the Commission will set test-year charitable contribution expense at \$887,977 and permit rate recovery of 50% of that amount.

## **XVI. Lobbying Expenses**

### **A. Introduction**

In its initial filing, the Company did not separately itemize its lobbying expenses, but simply included them as regular business expenses in other categories of test-year expense. The RUD-OAG examined the record and raised the issue in its direct testimony, challenging any inclusion of lobbying expenses in test-year expense.

### **B. Positions of the Parties**

#### **1. The RUD-OAG**

The RUD-OAG argued that lobbying expenses were not properly includible in rates, pointing out that they were not even deductible as regular business expenses under the Internal Revenue Code and that the Commission has historically rejected their inclusion in rates in other rate cases.

The Division recommended a total disallowance of \$350,000, which included all non-salaried lobbying costs, a portion of the salaries of three employees with lobbying responsibilities, the entire salary of the Vice President of Regulatory Affairs, and the cost of Company attendance at certain conferences the Division viewed as focusing primarily on influencing state and federal legislation.

The Division also recommended requiring Minnesota Power to adopt accounting practices treating lobbying expenses in the same manner as Xcel Energy, budgeting them to FERC Account 426.4, Civic and Political Expenses, and excluding them from test-year expense.

#### **2. Minnesota Power**

Minnesota Power argued that its lobbying activities "include public policy advocacy that is essential for Minnesota Power to fulfill its responsibilities as a public utility to its ratepayers."<sup>38</sup>

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<sup>38</sup> Initial brief of Minnesota Power, p. 73.

The Company argued that its legislative efforts were primarily directed at “[c]ontrolling mandated capital and O & M expenditures that cause rate increases and guiding various energy policy issues so that they do not unnecessarily drive up rates.”<sup>39</sup>

The Company cited as examples of ratepayer benefit its success in ensuring that cost impacts are a statutory factor requiring consideration in developing mercury abatement and renewable resource plans; opposing property tax increases; avoiding obligations to purchase uneconomic energy from qualifying facilities; and obtaining permission to postpone major environmental retrofit projects at its Boswell 4 coal-fired facility.

### **C. The Recommendation of the Administrative Law Judge**

The Administrative Law Judge found that, while the Company had indeed “supported legislation that would generally minimize costs for ratepayers, some ratepayers might well believe that cost reduction is less important than supporting renewable energy initiatives, limiting mercury emissions, or regulating coal combustion byproducts as hazardous waste.”<sup>40</sup> She concurred with the RUD-OAG that ratepayers should not be required to fund lobbying efforts in support of actions they might consider contrary to their convictions or best interests.

She recommended disallowing all lobbying expenses, which she found included \$105,335 in contract lobbying costs and \$115,000 in salaried employee expense. She found that the salary of the Vice President of Regulatory Affairs was not a lobbying cost, that the position existed primarily to monitor and ensure state regulatory compliance. Similarly, she found that the costs of conference attendance challenged by the RUD-OAG were not primarily for lobbying purposes and should be granted rate recovery.

Finally, she concurred with the RUD-OAG that Minnesota Power should be required to treat its lobbying costs in the same manner as Xcel Energy, budgeting both employee and contract lobbying expenses to FERC Account 426.4 and excluding this category from O & M expenses recovered from ratepayers.

### **D. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendations on this issue.

The RUD-OAG is correct that the Commission, as it stated in the last CenterPoint rate case, has consistently rejected rate recovery of lobbying expenses when that issue has been presented and addressed.<sup>41</sup> As the RUD-OAG points out, lobbying expenses are not considered ordinary and necessary business expenses under the federal Internal Revenue Code and are therefore not tax-deductible.<sup>42</sup> Similarly, they are not considered expenses necessary for the provision of utility service and are therefore not chargeable to ratepayers.

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<sup>39</sup> Initial Brief of Minnesota Power, p. 73.

<sup>40</sup> ALJ’s Report, ¶ 292.

<sup>41</sup> *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 46.

<sup>42</sup> 26 U.S.C. § 162 (e).

Finally, the Commission concurs with the ALJ that it is important to require the Company to adopt accounting procedures to readily identify lobbying expenses. The Commission will require the Company to record these expenses to FERC Account 426.4, Civic and Political Expenses, as she recommends.

## **XVII. Overall Financial Schedules**

### **A. Gross Revenue Deficiency**

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue deficiency for the 2010 test year of \$53,530,424, as shown below:

Description	Initial Filing	Commission Decision
Average Rate Base	\$ 1,009,049,722	\$ 1,043,371,807
Rate of Return	<u>8.95%</u>	<u>8.18%</u>
Required Operating Income	\$ 90,309,950	\$ 85,347,814
Operating Income	<u>\$ 42,886,948</u>	<u>\$ 53,962,918</u>
Income Deficiency	\$ 47,423,002	\$ 31,384,896
Gross Revenue Conversion Factor	<u>1.705611</u>	<u>1.705611</u>
Gross Revenue Deficiency	\$ 80,885,194	\$ 53,530,424

### **B. Rate Base Summary**

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional rate base for the test year ending 2010 is \$1,043,371,807, as shown below:

Rate Base Summary - Minnesota Jurisdiction  
Test Year Ending 12/31/2010

	<u>Initial Filing</u>	<u>Commission Adjustments</u>	<u>Commission Decision</u>
PLANT IN SERVICE			
Steam	\$ 1,008,176,296	\$ 5,442,339	\$ 1,043,618,635
Hydro	50,642,269	1,503,760	52,146,029
Wind	40,601,518	1,227,058	41,828,576
Transmission	263,572,124	10,730,162	274,302,286
Distribution	429,240,995	278,673	429,519,668

General	118,752,549	2,279,753	121,032,302
Intangible	<u>33,670,801</u>	<u>46,395</u>	<u>34,317,196</u>
Total Plant In Service	\$ 1,944,656,552	\$52,108,140	\$ 1,996,764,692
RESERVE FOR DEPRECIATION			
Steam	\$ 368,961,951	\$ 1,195,075	\$ 380,157,026
Hydro	26,962,177	800,608	27,762,785
Wind	2,234,917	67,544	2,302,461
Transmission	118,655,887	4,638,756	123,294,643
Distribution	176,308,156	121,585	176,429,741
General	58,889,275	1,130,526	60,019,801
Intangible	<u>26,769,442</u>	<u>513,907</u>	<u>27,283,349</u>
Total Reserve For Depreciation	\$ 778,781,805	\$ 18,468,001	\$ 797,249,806
NET PLANT IN SERVICE			
Steam	\$ 639,214,345	\$ 24,247,264	\$ 663,461,609
Hydro	23,680,092	703,152	24,383,244
Wind	38,366,601	1,159,514	39,526,115
Transmission	144,916,237	6,091,406	151,007,643
Distribution	252,932,839	157,088	253,089,927
General	59,863,274	1,149,227	61,012,501
Intangible	<u>6,901,359</u>	<u>132,488</u>	<u>7,033,847</u>
Total Net Plant In Service	\$ 1,165,874,747	\$ 33,640,139	\$ 1,199,514,886
Construction Work in Progress	\$ 35,306,464	\$ 3,950,609	\$ 39,257,073
Working Capital			
Fuel Inventory	\$ 16,252,347	\$ 365,558	\$ 16,617,905
Materials & Supplies	16,885,810	484,117	17,369,927
Prepayments	2,277,628	55,099	2,332,727
Cash Working Capital	<u>(10,341,111)</u>	<u>323,462</u>	<u>(10,017,649)</u>
Total Working Capital	\$ 25,074,674	\$ 1,228,236	\$ 26,302,910
Customer Advances	(2,645,921)	-	(2,645,921)
Customer Deposits	(337,079)	-	(337,079)
Accumulated Deferred Income Taxes	(210,671,420)	(4,696,766)	215,368,186

Unamortized Rate Case Expense	-	-	-
Unamortized WPPI Trans. Delivery Chg	(4,116,736)	(162,176)	(4,278,912)
Unamortized UMWI Transaction Cost	<u>564,993</u>	<u>362,043</u>	<u>927,036</u>
TOTAL AVERAGE RATE BASE	<u>\$ 1,009,049,722</u>	<u>\$ 4,322,085</u>	<u>\$ 1,043,371,807</u>

### C. Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the test year under present rates is \$53,962,918, as shown below:

Description	Initial Filing	Commission Adjustments	Commission Decision
<b>UTILITY OPERATING REVENUES</b>			
Residential	\$ 84,852,027	\$ 1,607,237	\$ 86,459,264
General Service	47,870,794	1,452,914	49,323,708
Large Light & Power	78,860,043	1,177,777	80,037,820
Large Power	200,820,472	52,694,557	253,515,029
Municipal Pumping	4,261,658	-	4,261,658
Lighting	<u>2,837,067</u>	<u>-</u>	<u>2,837,067</u>
Total Sales by Rate Class	\$ 419,502,061	\$ 56,932,485	\$ 476,434,546
Dual Fuel	8,324,000		8,324,000
Other Operating Revenue	<u>126,898,916</u>	<u>(3,419,157)</u>	<u>123,479,759</u>
Total Operating Revenue	\$ 554,724,977	\$ 53,513,328	\$ 608,238,305
<b>UTILITY OPERATING EXPENSES</b>			
Steam Production	\$ 63,138,141	\$ (846,118)	\$ 62,292,023
Hydro Production	4,614,092	133,229	4,747,321
Wind Production	884,741	26,739	911,480
Other Power Supply	2,849,967	86,132	2,936,099
Purchased Power and Interchange P. Fuel	<u>134,453,626</u> <u>109,124,282</u>	<u>3,298,954</u> <u>30,633,053</u>	<u>137,752,580</u> <u>139,757,335</u>
Total Production	\$ 315,064,849	\$ 33,331,989	\$ 348,396,838
Transmission and Regional Mkt.	\$ 25,436,995	\$ 571,622	\$ 26,008,617
Distribution	21,412,632	9,868	21,422,500
Customer Accounting	7,081,349	-	7,081,349

Customer Service & Info.	3,963,328	-	3,963,328
Conservation Improvement Program	4,624,108	-	4,624,108
Sales	165,828	(125,346)	40,482
Administrative and General	50,925,901	(1,044,483)	49,881,418
Charitable Contributions	505,161	9,688	514,849
Customer Deposits	18,000	-	18,000
Interest on LP Expedited Billings	<u>483,602</u>	<u>9,275</u>	<u>492,877</u>
Total O&M Expense	\$ 429,681,753	\$ 32,762,614	\$ 462,444,367
Depreciation Expense	\$ 59,844,444	\$ 1,372,425	\$ 61,216,869
Amortization Expense	1,003,685	144,810	1,148,495
Taxes Other Than Income	21,330,026	417,270	21,747,296
State Income Tax	(6,605,301)	1,673,846	(4,931,455)
Federal Income Tax	(19,728,279)	5,420,532	(14,307,747)
Provision for Deferred Income	35,511,108	860,578	36,371,686
Provision for Deferred Income - Cr.	(4,769,427)	(106,074)	(4,875,501)
Investment Tax Credit - Feedback	(672,992)	(15,861)	(688,853)
AFUDC	<u>(3,756,988)</u>	<u>(92,781)</u>	<u>(3,849,769)</u>
Total Utility Operating Expense	<u>\$ 511,838,029</u>	<u>\$ 42,437,358</u>	<u>\$ 554,275,387</u>
TOTAL OPERATING INCOME	<u>\$ 42,886,948</u>	<u>\$ 11,075,970</u>	<u>\$ 53,962,918</u>

### **XVIII. Future Sales Forecast Filings**

To facilitate record development in future rate cases, the OES recommended that the Commission order the following:

- The Company must provide all the data used in its test year sales forecasts at least 30 days prior to its future general rate case filings.
- The Company must continue working with the OES to improve the electronic linkage between its forecasting, revenue models, and Class Cost of Service Study (CCOSS), discussed below.
- If the Company acquires forecast-related data from third parties and subsequently relies on that data to make its sales forecasts in its next rate case, the Company must be prepared to provide verification of that data in response to requests by the parties.

The Administrative Law Judge recommended approval of the first two proposals but did not address the third. The Company subsequently acquiesced in all three proposals.

Given the importance of sales forecasts to establishing just and reasonable rates, the Commission concurs with the Administrative Law Judge and the parties. The Commission will therefore adopt all three proposals set forth above.

### **XIX. Marginal Cost of Service Study**

The next issues will address how to set rates to secure adequate revenues to enable the Company to cover its 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 designing rates, including economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect or otherwise compensate for additional costs; and in particular, the cost of service.

Estimating the cost a utility incurs to provide service is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. To aid this analysis a utility may conduct cost studies, such as a marginal cost study or a fully-allocated cost study.

A marginal cost study focuses on determining the cost the utility incurs to provide the next unit of service: a kW, a kWh, a new customer installation, etc. Among other things, a marginal cost study can be useful when the Commission seeks to establish prices for the purpose of influencing customer behavior to promote economic efficiency. The Administrative Law Judge recommended that the Commission direct the Company to provide a marginal energy cost study as part of its next rate case. The Commission concurs in the Administrative Law Judge's recommendation.

### **XX. Class Cost of Service Study (CCOSS)**

In contrast to a marginal cost study, a fully-allocated cost study is designed to apportion a utility's book costs among customers or customer classes. A study that seeks to allocate a utility's cost of service in proportion to the cost that each class of customer imposes on a system is called a Class Cost of Service Study (CCOSS).<sup>43</sup>

In designing its CCOSS, the Company considered several types of distinctions. It considered the various functions it performs. It considered the factors that cause the cost of performing each function to change. And it considered how different types of customers contribute to these factors.

*Functions:* A utility performs a variety of functions. For example, it generates electric energy, which reflects the capacity to do work. It also generates power, which reflects the capacity to get work done within a specific time. It also bills people for providing energy and power, collects payments, and responds to customer requests and complaints. For purposes of the CCOSS, the Company identifies 28 types of functions it performs.

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<sup>43</sup> Minn. Rules, part 7825.4300, subp. C, requires a company filing a rate case and proposing material changes to its rate structure to file a CCOSS.

*Allocation Factors:* Different factors drive the cost of each function. Certain costs are driven by the amount of energy customers want to consume (“energy costs”). Certain costs are driven by the need to have sufficient capacity to deliver the energy upon demand in the quantities needed to meet that demand (“demand costs”). And certain costs are driven by the number of customers the utility has (“customer costs”).

*Classes:* Finally, while each customer may influence these factors to a different extent, a residential customer will tend to use electricity in a manner similar to the usage of other residential customers, and dissimilar to the usage of, say, a city’s street lights. For ease of analysis, the Company considers how the factors driving costs are influenced by the consumption patterns of each of six categories of retail customers: Residential, General Service, Large Light and Power, Large Power, Municipal Pumping, and Lighting.<sup>44</sup>

People disagree about the optimal way to conduct a CCOSS. In this docket, parties disagree about the appropriate means for allocating the cost of production plant, energy-related costs, and income taxes. The Commission will address these issues in turn, starting with selecting a method for distinguishing demand-related production plant costs from energy-related plant costs.

## **A. Allocating Production Plant Costs Between Energy and Demand**

### **1. Introduction**

Does the amount that a utility must invest in production plant – electric generators and transmission lines – depend upon the amount of energy customers consume, or the maximum rate at which they consume it, or both?

Energy refers to the ability to do work; electrical energy is measured in terms of kilowatt-hours (kWh) or megawatt-hours (MWh). Power refers to the rate at which work can be done. It is measured in terms of kWh per hour and MWh per hour, or simply kW and MW. A utility incurs some costs in proportion to the amount of energy customers consume (energy costs). A utility incurs other costs in proportion to the rate at which the customer consumes energy, especially during periods of peak demand (demand costs).

In deciding what plant to build a utility must consider how much energy its customers will consume, as well as the maximum amount that they will want to consume at any given moment. The higher this peak demand level is, the more capacity the utility must acquire to meet that demand. For this reason, some people argue that plant cost should be allocated among customer classes in proportion to the amount of energy they demand during the period of peak system demand.

But others argue that utilities build a variety of generator plants, with a variety of costs, to fulfill different purposes. Some plants (peaker plants) have low construction costs but high operation costs; some plants (baseload plants) have high construction costs but low operating costs. A utility that builds a baseload plant rather than a peaker plant does not necessarily acquire more generating capacity; rather, the utility incurs higher construction costs to gain lower operating

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<sup>44</sup> A utility examines the relationship between variables – say, between the number of residential customers and the demand put on the system – by conducting load research. The Company relied on load research from 2003 for purposes of this rate case, but has agreed to start a new load research study by the end of 2011.

costs. Because the higher construction costs function as a substitute for higher operating costs, some people argue that a portion of a utility's plant costs should be allocated among customer classes in proportion to operating costs – that is, in proportion to energy-related costs.

## **2. Positions of the Parties**

Minnesota Power generally subscribes to this second theory by proposing the Peak and Average allocation method. This method allocates fixed production and transmission costs to each customer class based on both 1) the proportion of the Company's capacity that each class requires during the period of peak demand, and 2) each class's average level of demand – that is, each class's level of energy consumption. The Company advocated allocating production plant cost on the basis of both demand and energy.

The Minnesota Chamber of Commerce supported this allocation method. The OES also supported it for purposes of the current case, but indicated that they might propose a different method in a future rate case. With respect to each classification and allocation used in the Company's next CCOSS, OES asked the Company to provide a description, explanation, and reason why the Company's choices are superior to alternative classifications and allocations the Company considered; the Company has now agreed to this proposal.

The RUD-OAG opposed the Company's allocation method, arguing that it allocated a disproportionate share of costs to residential consumers. Instead of this method, the RUD-OAG proposed that the Company allocate the cost of its production plant among the customer classes in proportion to each class's energy consumption.

## **3. Recommendation of the Administrative Law Judge**

The Administrative Law Judge concluded that the Peak and Average method represented a reasonable means for allocating the cost of production plant among customer classes. In contrast, the Administrative Law Judge did not find any reasonable basis to allocate these costs solely on the basis of each customer class's energy consumption.

The Administrative Law Judge also concluded that the OES had articulated sufficient grounds to justify directing the Company to provide a more rigorous exposition and defense of the CCOSS it files in its next rate case. Consequently the Administrative Law Judge recommended that the Commission approve the OES's proposals.

## **4. Commission Action**

The Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendation on these issues.

The Company's Peak and Average allocation method recognizes the role that customer energy consumption and customer demand play in causing utilities to invest in production plant. In contrast, the RUD-OAG's proposal fails to give any weight to the role that peak demand plays in driving a utility's choice to invest in more capacity. Consequently in this case the Commission will approve of the use of the Peak and Average method for allocating production plant costs between demand and energy in the CCOSS.

The Commission also supports the parties' efforts to bring greater rigor to the analysis of the CCOSS process. With respect to each classification and allocation used in the Company's next CCOSS, therefore, the Commission will direct the Company to provide a description, explanation, and reason why the Company's choices are superior to alternative classifications and allocations the Company considered.

## **B. Allocation of Energy Costs among the Customer Classes**

### **1. Introduction**

After the Company identifies certain costs as being related to the amount of electricity generated, the Company must allocate these costs among the customer classes. Parties disagreed about the best method for doing so.

### **2. Positions of the Parties**

The RUD-OAG recommended allocating energy-related costs to customer classes in proportion to the amount of energy each class consumed.

The Company and the OES opposed this recommendation. They argue that this allocation fails to distinguish between expensive units of energy – consumed during periods of high demand – and inexpensive unit of energy – consumed during periods of low demand.

As discussed above, different generators have different operating costs. All else being equal, system operators will strive to meet customer demand by using their lowest-cost sources of energy first. When customer demand grows beyond the level that the low-cost generators can serve, system operators use their next least expensive sources, and so on. As a consequence, the Company argued, the cost of providing energy to a customer during periods of high demand will tend to be more than the cost of the same amount of energy during periods of low demand.

To reflect these cost differences, the Company used a more complex means of allocating energy-related costs. For each of the 8760 hours in a year, the Company identifies the cost of energy generated that hour, and then allocates the costs among customer class in proportion to each class's energy consumption during that hour. Customer classes that consume a disproportionate share of their energy during off-peak periods received the benefit of their lower-cost consumption patterns; customer classes that consume a disproportionate share of their energy during periods of peak demand were assigned costs accordingly.

The RUD-OAG opposed the use of this E8760 allocator for both factual and policy reasons. For example, the RUD-OAG objected that the E8760 relied on data from different years. Specifically, the Company used data about market prices from the 2008 test year, but data regarding customer usage from 2003.

As a matter of policy, the RUD-OAG objected to the use of the E8760 allocator on the grounds that it shifted costs among the customer classes in a manner that did not correspond with the amount of energy consumed by each class. In particular, the allocator tended to shift costs away from the Large Power class and toward the General Service and Residential classes.

### 3. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission approve the Company's use of the E8760 allocator as a reasonable method of allocating energy-related costs within the Company's CCOSS.

### 4. Commission Action

Because the E8760 allocator reflects the manner in which the cost of service varies with demand, the Commission has authorized its use in rate cases involving Minnesota Power,<sup>45</sup> Otter Tail Power Company,<sup>46</sup> and Northern States Power Company d/b/a Xcel Energy.<sup>47</sup>

The RUD-OAG correctly observes that the Company calculates its allocator on the basis of cost data from 2008 but customer usage from 2003. But no party has alleged that the 2003 data is inaccurate, or has articulated a basis to believe that the use of this data will generate a foreseeable bias to the benefit or detriment of any class. While the Company has committed to conducting a

new load research study, the Company also reports that this kind of data – showing how the aggregate demand by the residential class changes as the number of residential households change, for example – remains quite stable over time.

Finally, as the Company and the OES note, the only alternative in the record is to allocate energy-related costs solely on the basis of each customer class's energy consumption, without any recognition that energy costs vary over time. The E8760 allocator lends added precision to the CCOSS, even if calculated on the basis of seven-year-old load research data.

The Commission has considered the arguments advanced by the RUD-OAG, but is not persuaded that these arguments warrant abandonment of the E8760 allocator. Instead, the Commission concurs with the arguments advanced by the Company and the OES, and adopted by Administrative Law Judge, that the E8760 allocator provides a reasonable basis for allocating energy costs among the customer classes in this rate case. The allocator will be approved for use in this case.

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<sup>45</sup> See *In the Matter of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota* Docket No. E-015/GR-08-415, Docket No. E-015/GR-08-415 (May 4, 2009), citing with approval Findings of Fact, Conclusions and Recommendation (February 19, 2009), Findings 222-226.

<sup>46</sup> *In the Matter of the Petition of Otter Tail Power Company to Increase Rates For Electric Service*, Docket No. E-017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order (August 1, 2008) at 79.

<sup>47</sup> *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) at 29-30.

## **C. Allocation of Income Tax Costs among the Customer Classes**

### **1. Introduction**

Among the costs a utility must recover from its various customer classes is the cost of income tax. When designing a CCOSS, some assumption must be made about the company's level of taxable income, as well as the apportionment of the resulting taxes among the customer classes.

### **2. Positions of the Parties**

For purposes of the CCOSS, the Company proposed estimating each class's income tax bill based on the Company's current rates. The Company reasoned that Commission-approved rates could not be regarded as an arbitrary basis for analysis.

The OES and the RUD-OAG objected that this practice would needlessly contaminate the CCOSS with the policy decision reflected in current rates. To avoid this problem, the OES recommended the Company calculate each class's net taxable income on the assumption that the Company charged rates derived solely from the CCOSS.

### **3. Recommendation of the Administrative Law Judge**

The Administrative Law Judge concluded that the OES had articulated the better argument, and recommended that the Company revise the manner in which it allocates income tax expenses to customer classes in future CCOSSs.

### **4. Commission Action**

The purpose of the CCOSS is to create a formula for allocating a utility's costs among its customers on the basis of abstract principles of cost-causation alone. While ultimately a CCOSS cannot avoid the intrusion of policy judgments, the Commission strives to minimize them – not because policy judgments are unimportant, but because the Commission has the opportunity to consider them in the context of setting rates. The CCOSS provides the best opportunity to create a yardstick for evaluating cost, abstracted to the maximum extent possible from policy concerns.

Consequently the Commission finds the OES's arguments persuasive. By calculating each class's income tax burdens based on the CCOSS, the Commission can minimize the role of policy determinations in the creation of the CCOSS. Therefore the Commission concurs with the Administrative Law Judge, and adopts her findings, conclusions, and recommendation: The Commission will order the Company to file CCOSSs in future rate cases that calculate and assign income taxes based on each class's adjusted net taxable income as determined by the CCOSS.

## **D. Conclusion**

Having reviewed the arguments of the parties and rendered decisions for modifying the Company's CCOSS prospectively, the Commission will adopt the recommendation of the Administrative Law Judge and accept Minnesota Power's CCOSS as the starting point for designing rates.

On that basis the Commission concludes that, if the Company were to increase its revenues by \$ 70.5 million (or 15.1%) and each customer class contributing an amount equal to its cost of service as identified in the CCOSS, the Company would need to increase the contribution of each customer class by the following amounts:

	Increase needed to conform to CCOSS
Residential	29.5%
General Service	9.3%
Large Light & Power	9.0%
Large Power	13.9%
Municipal Pumping	11.0%
Lighting	6.4%
Weighted average	15.1%

## **XXI. Interclass Revenue Apportionment**

### **A. Introduction**

Having resolved questions establishing the size of the Company's retail revenue requirement for Minnesota, the Commission must set rates that will provide a prudently-managed utility in the Company's circumstances with a reasonable opportunity to recover these revenues. The next step in that process is to determine how much each retail customer class should be expected to contribute to meeting that revenue requirement. As discussed above, the Commission makes these rate design decisions on the basis of the cost of service; economic efficiency; continuity with

prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; ability to bear, deflect or otherwise compensate for additional costs; and other considerations.

### **B. Positions of the Parties**

Generally, the positions of the parties appear on a continuum between proposals that primarily reflect the results of the CCOSS and proposals that reflect current class revenue responsibility.

#### **1. Apportionment based primarily on the CCOSS**

On one end of the apportionment continuum, the Minnesota Chamber of Commerce and the Large Power Intervenors each recommend apportioning revenue responsibility primarily on the basis of the CCOSS, according relatively little weight to non-cost considerations. Nevertheless, both parties support deviating from the CCOSS to reduce the burden on the Residential class to some extent.

The Minnesota Chamber of Commerce initially supported apportioning revenue responsibility in accordance with the CCOSS, but subsequently conceded that it would be unwise to increase the revenue responsibility of the Residential class by 29.5% in a single rate case. Instead, the Chamber recommended limiting the increase for the Residential class to 4.5% less than the share indicated by the CCOSS.

The Large Power Intervenors asked the Commission to allocate revenue responsibility in a manner that comes closer to the CCOSS allocation than the status quo. In specific, these Intervenors asked the Commission to adopt the Company's proposed class revenue apportionment (discussed below) but modified to increase the Residential class's share by \$3 million and reduce all other classes' shares proportionately.

These parties generally argued that deviations from a CCOSS apportionment result in certain classes of customers subsidizing other classes. According to the Chamber and the Intervenors, this practice results in a variety of harms: It causes electricity for members of the subsidized class to be unduly cheap, discouraging efficient levels of conservation. It causes electricity for the subsidizing classes to be unduly expensive, encouraging inefficient levels of conservation. And it is simply unfair to members of the subsidizing classes.

Neither the Chamber nor the Joint Intervenors recommend setting the Residential class's revenue requirement in this rate case equal to the allocation set forth in the CCOSS. But the Chamber and the Intervenors also questioned the merits of diverging from the allocation indicated in the CCOSS as a means to aid low-income residential customers. They argued that the Company's Lifeline Rider – a program intended to target subsidies to low-income households based on demonstrated need -- represents a more efficient means for achieving that end. And they argued that increasing the cost of electricity for businesses will tend to depress economic activity – and therefore employment and tax revenues -- in the Company's service area, which may have a more deleterious effect on members of the Residential class than a marginally larger electric bill.

The RUD-OAG argued that the Minnesota Chamber of Commerce and the Large Power Intervenors place undue emphasis on the role of the CCOSS, a tool that the RUD-OAG deems to be unreliable. In response, the Large Power Intervenors argued that if the CCOSS errs, it is because the CCOSS has assigned insufficient costs to the Residential class; moreover, they argued that the RUD-OAG offers no meaningful alternative for evaluating the cost of service.

## **2. Apportionments balancing cost and non-cost factors**

Closer to the center of the continuum, the Company and the OES each proposed apportionments reflecting their views that cost and non-cost factors are more closely balanced.

The Company proposed to increase the Residential class's revenue responsibility in proportion to the increase in the Company's Minnesota revenues from retail sales. Under this formula, if the Commission were to authorize the Company to increase its revenues by 15% the Residential class's revenue responsibility would also increase by 15%. The Company would propose to recover the balance of its revenue increase from the other customer classes in proportion to each class's revenues. The Company defends this allocation formula on the grounds that it does not ask any class to bear any larger share of the Company's costs than they do now.

The OES initially proposed limiting any increase in the Residential Class's revenue responsibility to 12%, the same increase authorized for that class in the Company's last rate case, and to allocate the balance of the revenue increase proportionately among the remaining customer classes. In the context of a \$70.5 million (15.1%) rate increase, this formula would result in the following allocations:

	Current Class Revenue (in millions)	Increase needed to conform to CCOSS	Proposed Increase in Class Revenues	Proposed Class Revenues (in millions)	Class Revenues as % of Total Revenues
Residential	\$86.3	29.5%	12.0%	\$96.6	18.0%
General Service	\$49.0	9.3%	9.3%	\$53.5	10.0%
Lrg Lgt & Pwr	\$79.9	9.0%	13.1%	\$90.4	16.8%
Large Power	\$244.0	13.9%	18.1%	\$288.2	53.7%
Muni. Pumping	\$4.3	11.0%	15.1%	\$4.9	0.9%
Lighting	\$2.8	6.4%	10.5%	\$3.1	0.6%
Average or Total	\$466.3	15.1%	15.1%	\$536.8	100.0%

If the Commission were to authorize the Company to increase revenues by less than 15.1%, however, the OES would recommend adjusting the increases to each class as necessary to preserve each class's share of the Company's revenue requirement set forth above. In other words, under this formula the Residential class would be responsible for providing 18% of the Company's revenues, whether the Commission approved a revenue increase of 15.1% or something less.

The Residential class is the only customer class that does not contribute at least as much revenue as the CCOSS would prescribe. Both the Company and the OES ask the Commission increase the share of revenues to be contributed by the Residential Class, thereby bring the share borne by the Residential class closer to the share stated in the CCOSS.

The OES noted that the Commission had authorized increasing the Residential class's revenue responsibility by 12% in 2008, while increasing the allocation to the Large Power customers by only 2.2%. The OES considered the combined consequences of this rate case and the prior one when determining its apportionment recommendations in this case.

### **3. Apportionment based on non-cost factors**

On the other end of the continuum are the positions of the Energy CENTS Coalition and the RUD-OAG. They share the OES's view that the Commission should apportion costs among customer classes in light of the allocations approved in the Company's 2008 rate case. For this and other reasons, these parties recommend refraining from authorizing any increase in the revenue responsibility of the Residential class. The RUD-OAG recommends forgoing any increase for the General Service class as well.

Because the Company has had to design its system to meet the needs of its Large Power customers, the Coalition and the RUD-OAG advocated having that class bear a larger portion of the Company's costs. In particular, the RUD-OAG suggested allocating the cost of the Company's expensive generation and transmission assets in proportion to the amount of energy consumed by each customer class.

But whatever the merits of apportioning the Company's revenue requirement based on the cost of service, the Coalition and the RUD-OAG argue that the record lacks a reliable means for measuring cost because any CCOSS is irreducibly arbitrary. Consequently these parties deny that

a CCOSS provides any basis for judging when one customer class is subsidizing another, or that deviating from the CCOSS' class allocations would result in inappropriate price signals that might distort consumer behavior.

In contrast to this weak record regarding cost, the Energy CENTS Coalition and the RUD-OAG emphasize the uncontested record regarding the hardship many residential customers are experiencing in the current economy. The Coalition filed testimony regarding growing rates of poverty and service disconnections in the Company's service area, and noted the statements received from customers during public hearings in Eveleth, Duluth, Grand Rapids, and Little Falls.

The Energy CENTS Coalition dismisses concerns that apportioning less cost to the Residential class than the CCOSS prescribes would undermine efforts to promote residential energy conservation. Other mechanisms -- such as an inclining block rate structure, discussed below -- provide more effective means for encouraging conservation, the Coalition argues.

In response, the Minnesota Chamber of Commerce, the Large Power Intervenors and the Company stated that industrial customers are also experiencing hardship, and that these customers face competitive pressures from firms in other jurisdictions that may offer lower electric rates. The average business spends a larger share of its budget on electricity than the average household does, these parties argued, and a residential customer would endure less harm from a slightly larger rate increase than from losing a job because an employer found it could no longer operate due to higher energy costs.

The RUD-OAG countered by noting that electricity bills are a cost of business to industrial customers -- a cost that may be deducted from revenues for tax purposes, and that may be passed through to customers via higher prices; residential customers lack these options. Finally, the RUD-OAG argued that businesses will be better able to thrive when residential consumers achieve greater economic stability; undue increases in their electric bills would impede that goal.

### **C. Recommendation of the Administrative Law Judge**

After summarizing the positions of the parties, the Administrative Law Judge concluded that the OES's proposed apportionment reflected the most reasonable balance of competing considerations. According to the Administrative Law Judge, implementing this apportionment would cause all customer classes to contribute to offsetting the Company's growing costs without causing unacceptably drastic changes for any class.

As a consequence of other recommendations by the Administrative Law Judge, the net revenue deficit supported by the ALJ's Report was reduced to roughly \$55 million. Applying the OES's proposed allocation formula to a revenue increase of that magnitude produces the following class revenue allocations:

	Class Revenue Apportionment (in millions)	% of Total Revenue	\$ Increase (in millions)	% Increase
Residential	\$93.8	18.0%	\$6.8	7.8%
General Service	\$51.9	10.0%	\$2.3	4.5%
Large Light & Power	\$87.8	16.9%	\$7.4	9.2%
Large Power	\$279.8	53.7%	\$36.9	15.2%
Municipal Pumping	\$4.7	0.9%	\$0.5	11.6%
Lighting	\$3.0	0.6%	\$0.2	8.4%
Total Firm Service Revenues <sup>48</sup>	\$521.1	100.0%	\$54.1	11.6%

The Minnesota Chamber of Commerce, the Large Power Intervenors, and the Company each took exception to the Administrative Law Judge’s recommendation, largely for reasons previously stated. The Chamber and the Intervenors denied that their proposals would result in any greater rate shock than the Company’s or OES’s initial proposals. And the Chamber and the Large Power Intervenors objected to the Administrative Law Judge’s characterization of their positions.

As a compromise, the Large Power Intervenors ask the Commission to adopt the Company’s allocations in lieu of the Administrative Law Judge’s recommendations.

#### **D. Commission Action**

It is sometimes implied that the CCOSS represents the ideal allocation of revenue responsibility among the customer classes. While no party asked the Commission to require the Residential class to contribute the proportion prescribed in the CCOSS, various parties have asked the Commission to ensure that the Residential class moves toward contributing the share designated in the CCOSS. But, while the Commission is not persuaded that the CCOSS is as unreliable as the RUD-OAG argues, neither is the CCOSS the infallible guide to cost of service that others may suggest. Moreover, as noted before, cost is but one factor the Commission considers when setting rates.

Having reviewed the positions of the parties, the Commission concurs with the arguments offered by the OES, the Energy CENTS Coalition, the RUD-OAG, and members of the public. Given the state of the economy, combined with the Commission’s recent decision authorizing a 12% rate increase for the Residential and General Service classes while holding the Large Power class to a 2.2% increase, the Commission will decline to authorize another Residential rate increase of that magnitude at this time.

Various parties suggest that the Commission refrain from considering how increasing the Residential class’s revenue requirement would affect low-income customers, arguing that the Company’s Lifeline Rider program would provide a means for addressing these concerns. For reasons addressed in the discussion of the Residential class rate design, the Commission will decline to adopt the Lifeline Rider. Consequently that proposal has no bearing on the Commission’s analysis of proposed interclass revenue apportionments.

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<sup>48</sup> Revenues from firm service + revenues from other services (interruptible, etc.) = \$55 million.

To summarize, the OES’s formula would increase the Residential class’s revenue responsibility by no more than 7.8%. In contrast, the Coalition and the RUD-OAG caution against providing any increase to that class. Having reviewed the positions of the parties, the Commission concludes that a compromise among the positions advocated by the OES, the Energy CENTS Coalition, and the RUD-OAG will provide the most balanced consideration of cost and non-cost-based factors.

Consequently the Commission will limit the growth of the Residential class’s revenue responsibility to no more than 3.9%, the midpoint between the position of the OES and the position of the Coalition/RUD-OAG. The Company will be able to recover the balance of its revenue increase from its other classes. This apportionment will require all customer classes to bear a portion of the Company’s increased cost of service, while also shielding residential customers from the bulk of the rate increase in this particularly challenging economic climate. The Commission will design rates intended to permit the Company to increase its revenues from each firm customer class, but not beyond the levels set forth below:

	Class Revenue Apportionment (in millions)	% of Total Revenue	\$ Increase (in millions)	% Increase
Residential	\$90.5	17.4%	\$3.4	3.9%
General Service	\$52.3	10.0%	\$2.7	5.4%
Large Light & Power	\$88.5	17.0%	\$8.1	10.0%
Large Power	\$282.0	54.1%	\$39.1	16.1%
Municipal Pumping	\$4.8	0.9%	\$0.5	12.5%
Lighting	\$3.0	0.6%	\$0.3	9.2%
Subtotal	\$521.1	100.0%	\$54.1	11.6%

## XXII. Residential Rate Design

Having determined the share of the Company’s Minnesota retail revenue requirement to be recovered from each customer class, the Commission must now determine how to design rates for the Residential Class.

### A. Introduction

Parties have proposed a variety of designs for residential rates, including the following mechanisms:

- Increasing the customer charges.
- Increasing the price per kWh within each rate block, and increasing the number of blocks.
- Establishing an affordability program.

*Customer charges.* A *customer charge* refers to a monthly fee the Company charges each residential customer. Most customers receive Residential General service and pay the Residential General customer charge. The Company also offers Residential Dual Fuel service for residential customers that rely on electricity for heating but also have access to an alternative source of heating energy, and Residential Seasonal service for residential customers that take service for only part of the year – typically, for a cabin that is not used in the winter. Each of these services has its own customer charge. The Company proposed to increase the customer charge for all of its residential services.

*Rate blocks.* The Company does not charge Residential General customers a uniform rate per kWh; rather, the rate the Company charges increases as the customer’s usage increases. Currently a customer receiving Residential General service pays no incremental charge for the first 50 kWhs consumed per month, \$0.04773 for each of the next 300 kWhs consumed that month, and \$0.08004 per kWh thereafter. Each change in rate denotes a separate *rate block*. Because the rates increase with usage, this rate design is called an *inclining rate block*. Various parties recommended changing the price per kWh charged within each rate block, as well as changing the number of blocks.

*Affordability program.* At the Commission’s direction,<sup>49</sup> the Company developed a Lifeline Rider proposal to enable qualified residential customers with low income to receive electrical service at lower rates.

## **B. Positions of the Parties**

The parties’ positions are set forth in the following table:

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<sup>49</sup> *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order (May 4, 2009) at 84.

**Residential Rate Design: Positions of the Parties**

Minnesota Power General	Minnesota Power Alternative	OES General	RUD-OAG General	Energy CENTS Coalition General	Minnesota Power's Lifeline Rider
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**Customer Charge per month: Residential General , Dual Fuel, Seasonal**

	Minnesota Power General	Minnesota Power Alternative	OES General	RUD-OAG General	Energy CENTS Coalition General	Minnesota Power's Lifeline Rider
General	\$9.75	\$8.00	\$8.00	\$8.00	\$8.00	\$8.00
Dual Fuel	\$9.75	\$9.75	\$8.00			n/a
Seasonal	\$11.00	\$11.00	\$8.80			n/a

**Energy Charge per kWh: Residential General, Lifeline Rider**

	Minnesota Power General	Minnesota Power Alternative	OES General	RUD-OAG General	Energy CENTS Coalition General	Minnesota Power's Lifeline Rider						
1-50 kWh	Block 1: \$0	Block 1: \$0	Block 1: \$0	Block 1: \$0	Block 1: 76% of Block 2 rate;	Block 1: \$0						
51-100	Block 2: \$.04773 to \$.06966 <sup>[A]</sup>	Block 1: \$.04773 to \$.06471 <sup>[A]</sup>	Block 2: \$.04773 to \$.07550 <sup>[A]</sup>	Block 2: 60% of Block 3 rate; \$.04773 to \$.06336 <sup>[A]</sup>	\$.05510 <sup>[B]</sup> or less	Block 2: equals General Block 2 rate less \$.01266						
101-150												
151-200												
201-250												
251-300												
301-350	Block 3: \$.08004 to \$.09650 <sup>[A]</sup>	Block 2: \$.08004 to \$.09650 <sup>[A]</sup>	Block 3: \$.08004 to \$.09650 <sup>[A]</sup>	Block 3: \$.08004 to \$.10560 <sup>[A]</sup>	Block 2: \$.07273 <sup>[B]</sup> or less	Block 3: equals General Block 3 rate						
351-400												
401-450												
451-500												
501-550												
551-600												
601-650												
651-700												
<b>701-750</b>							<b>T Y P I C A L U S A G E</b>				<b>E L E V E L</b>	
751-800							Block 3: 121% of Block 2 rate; \$.08816 <sup>[B]</sup> or less	Block 4: 125% of Block 2 rate; \$.09115 <sup>[B]</sup> or less	Block 5: 133% of Block 2 rate; \$.09642 <sup>[B]</sup> or less	Block 5: 133% of Block 2 rate; \$.09642 <sup>[B]</sup> or less	Block 4: 125% of Block 2 rate; \$.09115 <sup>[B]</sup> or less	Block 5: 133% of Block 2 rate; \$.09642 <sup>[B]</sup> or less
801-850												
851-900												
901-950												
951-1000												
1001 +												

**Maximum bill for 750 kWh per month, Residential General service**

	Minnesota Power General	Minnesota Power Alternative	OES General	RUD-OAG General	Energy CENTS Coalition General	Minnesota Power's Lifeline Rider
750 kWh	\$69.25 <sup>[A]</sup>	\$69.25 <sup>[A]</sup>	\$69.25 <sup>[A]</sup>	\$69.25 <sup>[A]</sup>	\$61.12 <sup>[B]</sup>	\$63.70 <sup>[A]</sup>

<sup>[A]</sup>Assumes Minnesota revenue increase of \$81 million; see Company rate case filing.

<sup>[B]</sup>Assumes Minnesota revenue increase of \$55 million; see Company compliance filing (September 1, 2010), Sch. 7.

(The lower number within a price range is the Company's current charge; the higher number is an estimate generated on the basis of a given Residential class revenue requirement.)

**1. Minnesota Power's Initial Proposal**

*Customer charge.* First, the Company proposed increasing the customer charges for Residential General service, Residential Dual Fuel service and Residential Seasonal service. The Company argued that the CCROSS demonstrates that the Company incurs fixed customer-related costs in

providing these services – costs for meter reading, billings, collections, and the like -- well in excess of what the Company recoups through its existing customer charges.

In addition, the Company provided evidence that neighboring electric cooperatives charge still higher customer charges.

The Energy CENTS Coalition, the OES, and the RUD-OAG opposed increases to the customer charge for Residential General service; the OES also opposed increases for Residential Dual Fuel and Residential Seasonal services as well. Parties argued variously as follows:

- The Company's Residential General customer charge is already higher than the analogous customer charge assessed by any other regulated utility.
- The Company only recently increased the Residential General customer charge by 60% -- from \$5.00 to \$8.00 -- and consumers would resent a further increase.
- A larger customer charge would result in lower energy charges, which would tend to discourage conservation.
- The CCOSS is not a reliable basis for judging cost of service and, in any event, concern for affordability should prompt the Commission to deny this rate increase.

*Energy Charge.* In its initial filing the Company proposed to continue its practice of assessing no incremental charge for the first 50 kWh that a customer used each month, reasoning that the customer charge already covers these costs. To generate most of the revenues needed to recover the Residential Class's increased revenue requirement, the Company proposed increasing the energy charge in Rate Blocks 2 and 3. Quantifying this increase is challenging due to the changing assumptions about the magnitude of the Company's revenue increase; the preceding table sets forth estimates.

As discussed in the context of class revenue apportionment, RUD-OAG disputed the reliability of the CCOSS as a tool for measuring the cost of service. In addition, the Energy CENTS Coalition joined the RUD-OAG in questioning whether members of the residential class could afford to bear these rate increases at this time. The Company, the Minnesota Chamber of Commerce and the OES generally argued that the proposed Lifeline Rider would remedy problems of affordability.

*Lifeline Rider.* To reduce the burdens the Company's rate increases would pose to low-income customers, the Company proposed its Lifeline Rider affordability program. A consumer that qualified for the federal Low-Income Home Energy Assistance Program (LIHEAP) would be eligible to receive electric service at a discount. The Company would charge a qualified customer \$8.00 for a customer charge, \$0 for the first 50 kWh consumed per month, and a discount rate for the next 300 kWh equal to the price of the Residential General services Block 2 less \$0.01266 per kWh.<sup>50</sup> Beyond 350 kWh per month, a Lifeline Rider customer would pay the same rate per kWh as a Residential General customer.

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<sup>50</sup> The Company adopted this position in its Summary of Decision Options (September 28, 2010).

Applicants would need to re-apply and demonstrate eligibility annually to continue receiving the rider's benefits. The Company stated that it had received verbal assurance that energy assistance and social service agencies would be available throughout the year to verify ratepayers' eligibility.

The Company estimates that 30,000 to 36,000 of its 108,700 residential customers may be eligible for the Lifeline Rider, yet only 11,856 of these customers were enrolled in LIHEAP. The Company sent a mailing to 30,000 customers who might be eligible for LIHEAP funding but recruited only 786 new LIHEAP-eligible customers.<sup>51</sup> The Company predicted that its customers would subscribe for the Lifeline program at a greater rate than they subscribed for the LIHEAP program.<sup>52</sup>

The Minnesota Chamber of Commerce and the OES generally supported the Lifeline Rider. The Company's current rate design shifts costs away from households that consume little energy, with the expectation that this has the effect of shifting costs away from households with low income. The Chamber and the OES reasoned that the Rider would target assistance to low-income households, regardless of the amount of energy consumed in the household. This fact would free the Company to design its Residential General rates in a manner that more closely tracks the cost of service.

The Energy CENTS Coalition and the RUD-OAG opposed the Company's proposal to replace its current Residential General rate design with its proposed new Residential General rates and the Lifeline Rider. The Coalition and the RUD-OAG made four principal arguments.

First, they questioned the feasibility of the Company's proposal to registers tens of thousands of customers when it had fewer than 12,000 customers registered for LIHEAP – a program that offers a much larger subsidy.

Second, they questioned the adequacy of the discounts offered by the Rider. Their analysis demonstrated that subscribers to the program would typically receive a discount of less than \$4.00 per month relative to the proposed Residential General rates. If the Commission did not grant the Company's full revenue increase, then the Company's standard rates would be even lower and the likely savings would be even less.

Third, they questioned the adequacy of the rider's scope, and challenged the wisdom of implementing a policy that narrows the scope of assistance during a time of widespread economic distress. The Energy CENTS Coalition argued that many households that do not qualify for the LIHEAP program may nevertheless find themselves struggling in the current economic environment. Citing the service area's low median income and high unemployment rate, these parties urged the Commission to err on the side of caution; these are not auspicious times to implement new restrictions on assistance, no matter how well intentioned.

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<sup>51</sup> In its exceptions to the ALJ's Report the Company revised its answer and reported that it achieved a 2.69% response rate. Exception of Minnesota Power (September 1, 2010) at 19.

<sup>52</sup> *Id.*

Finally, members of the public -- including representatives of the Minnesota Seniors Federation Northeast -- objected to the Lifeline Rider during public hearings in Eveleth, Duluth, Grand Rapids, and Little Falls. Many expressed concern about the burdens of applying and re-applying annually to qualify for the program.

## **2. Minnesota Power's Alternative Proposal**

As an alternative, the Company offered a variation on its initial proposal. Instead of increasing the Residential General customer charge to \$9.75, the Company would retain the \$8.00 fee but begin charging customers for the first 50 kWh of usage each month -- in effect, eliminating the first rate block and expanding the second. The arrangement would have the benefits of keeping the customer charge lower while charging for each unit of energy consumed, thereby encouraging conservation.

The OES and the RUD-OAG opposed this proposal on the grounds that it would likely end up imposing greater costs on residential customers with low rates of energy consumption than would the Company's initial proposal.

## **3. The OES's Proposal**

The OES generally supported the Company's residential rate design for purposes of the current case -- including the Company's Lifeline Rider -- but with a few modifications. In particular, the OES recommended that the Commission retain both the Company's current \$8.00 customer charge for Residential General service and the current practice of imposing no incremental charge for the first 50 kWh each month.

Yet ultimately the OES acknowledged the difficult trade-offs required to design rates for the Residential class and stated that it could support any of the decisions before the Commission.

## **4. The RUD-OAG's Proposal**

The RUD-OAG asked the Commission to keep the Company's Residential General customer service charge at \$8.00 and to maintain the practice of imposing no additional charge for a household's first 50 kWh of service each month. In addition, the RUD-OAG recommends that the Commission keep the price of energy in Block 2 at no more than 60% of the price of energy in Block 3, just as it is under current rates. In this manner the RUD-OAG seeks to ensure that households with low energy usage do not bear any more than their fair share of the Company's increased costs.

## **5. The Energy CENTS Coalition**

The Energy CENTS Coalition also wrestled with how to ensure that households with low income did not bear a disproportionate share of the Company's costs -- while acknowledging that the Company was entitled to recover those costs from someone. The Coalition recommended that the Commission retain the Company's current \$8.00 customer charge for Residential General service. But to relieve the pressure to increase the rates in Blocks 2 and 3 while also maintaining the

customer charge at current levels, the Coalition recommended that the Commission adopt a rate design similar to the one it approved in CenterPoint Energy's most recent rate case – that is, a design using five inclining rate blocks.<sup>53</sup>

The Coalition even proposed retaining the same price ratios among the blocks as the Commission approved in that case. As depicted in the prior chart, the Company would set the price for Block 2 as necessary to generate the appropriate revenues. The price of Block 1 would be 76% of the Block 2 price. The price in Blocks 3, 4, and 5 would be 121%, 125% and 133% of the Block 2 price, respectively.<sup>54</sup> Combined, these blocks would provide a formula to compensate the Company for providing electric service while providing each customer with an incentive to conserve that increases as the customer's energy consumption increases.

The Energy CENTS Coalition reasoned that additional rate blocks would enable a rate design that would reduce the funds recovered from households with low rates of energy consumption, and increase the recovery from households with higher rates of energy consumption. Because energy consumption tends to increase with income, the Coalition reasoned that this rate design would tend to benefit low-income consumers more than any of the alternatives presented.

The Joint Intervenors supported this proposal, arguing that it was calculated to achieve an appropriate balance between promoting conservation and promoting affordability.

In contrast, the Company, the Minnesota Chamber of Commerce and the OES opposed the Energy CENTS Coalition's proposal. They noted that the Commission adopted the CenterPoint Energy rate design as part of a larger pilot program, and argued that those rates have not been in place long enough to permit any meaningful analysis. They argued that changing the rate design would needlessly confuse customers when they will already be feeling frustration with a new rate increase. And they warned that the Energy CENTS Coalition's rate design would create hardship for households with both low incomes and high energy usage.

The Company, the Minnesota Chamber of Commerce, and the OES argued that the better way to address the Energy CENTS Coalition's concerns was via the proposed Lifeline Rider.

The Energy CENTS Coalition acknowledged that its proposed rate design alleviates burdens on low-usage households, not high-usage households. Nevertheless the Coalition argued that this rate design would tend to benefit low-income households because low-income households tend to use less energy. In addition, the Coalition argued that there are limited ways to grant relief to households with low energy usage: It is difficult to encourage additional conservation beyond a certain point, and the return on conservation investments is diminished when there is less energy use to be conserved.

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<sup>53</sup> *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 13-15.

<sup>54</sup> See Minnesota Power compliance filing (September 1, 2010), Sch. 7.

In contrast, the Energy CENTS Coalition argued, there are a variety of means to promote conservation among households with high energy usage. To this end, the Coalition further recommended that the Commission direct the Company to develop a program designed to identify and mitigate the problems of high-usage, low-income households similar to a program implemented by Northern States Power Company d/b/a Xcel Energy (Xcel).<sup>55</sup>

Xcel's program has two components: a discount component and an affordability component. Under the discount component, a person who has qualified for assistance under the Low Income Home Energy Assistance Program (LIHEAP) within the current federal fiscal year, and who is a senior or has a disability, may qualify for a 50% discount on the first 400kWh consumed each month. Under the Power On affordability component, a household that spends more than 3% of its income for electric service and that typically consumes more than 750 kWh per month may qualify for a discount on future electric bills if the ratepayers agree to a payment plan. Xcel works with social service agencies to verify a household's qualifications.

### **C. Recommendation of the Administrative Law Judge**

After acknowledging the important interests advocated by the parties, the Administrative Law Judge identified the two conclusions that proved most salient to her analysis: First, due to the combined effect of the economy on the ratepayers in Minnesota Power's service area and the recent, sizable rate increase they have already absorbed, this is not an opportune time for a substantial new increase in residential rates. Second, the record leaves substantial doubt about whether the Company would be able to get its 20,000 low-income households to subscribe and fulfill the qualifications for the proposed Lifeline Rider in a timely fashion.

These conclusions, among others, prompted the Administrative Law Judge to recommend designing the residential rates in a manner that would protect low-income households from the consequences of the Company's increasing cost of service. Specifically, the Administrative Law Judge recommended that the Commission refrain from raising any of the residential customer charges. And the Administrative Law Judge recommended that the Commission refrain from approving the Lifeline Rider at this time due to concerns about the logistics of implementing this new program during this period of heightened need.

Instead, the Administrative Law Judge recommended that the Commission structure the Company's standard residential rates in a manner that would reduce the share of revenues recovered from households with low electricity consumption and recover the balance from households with higher usage levels. To this end, the Administrative Law Judge recommended that the Commission adopt the Energy CENTS Coalition's proposal to expand the Residential General rate design to five rate blocks, with a customer's price per kWh increasing as usage increased. While the OES expressed concern that ratepayers would be confused by the addition of two new rate blocks, the Administrative Law Judge concluded that ratepayers would find this rate design less confusing than the proposed Lifeline Rider.

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<sup>55</sup>See, for example, *In the Matter of a Petition by Northern States Power d/b/a Xcel Energy for Approval of a Modification to the Company's Low-Income Discount Program*, Docket No. E-002/M-04-1956, Order Adopting Additional Reporting Requirements for Electric Low-Income Discount Program (September 16, 2010).

## **D. Commission Action**

### **1. Introduction**

As stated at the outset, the Commission's task is to design rates to promote the public interest while providing the Company with a reasonable opportunity to earn its revenue requirement. At this stage of the analysis, the revenue requirement is fixed. Consequently the task of designing rates becomes akin to pushing on a balloon: pushing down on one part must result in pushing up some other part.

Having reviewed the record, including the oral and written arguments of all parties and members of the public, the Commission finds that the Administrative Law Judge has given appropriate recognition to the challenges posed by this case: the Company's demonstrated need for additional revenues, the ongoing economic distress in the Company's service area, and a residential class that just recently absorbed a sizable rate increase. This context heightens the importance of designing rates with an eye to mitigating adverse consequences for low-income ratepayers. With that goal in mind, the Commission finds that the ALJ has identified the most promising combination of rate design elements. The Commission will adopt the Administrative Law Judge's findings, conclusions, and recommendation on this issue as modified below.

### **2. Customer Charge**

The Commission will adopt the Administrative Law Judge's recommendation to maintain Residential customer charges at current levels. The Commission is reluctant to increase these charges. Customer charges do not vary with usage, and no amount of conservation permits a customer to reduce these costs -- short of disconnection. And given that the Company has only recently increased the Residential Basic customer charge by 60%, the Commission will decline to authorize another increase at this time.

### **3. Lifeline Rider**

The Commission will adopt the Administrative Law Judge's recommendation and decline the Company's Lifeline Rider proposal at this time. The record supporting the Lifeline Rider is not adequately developed to enable the Commission to conclude with confidence that the program would facilitate enrollment of a sufficient number of the roughly 20,000 low-income households in the Company's service area. Given the state of the economy in the Company's service area, the Commission concludes that the more prudent course of action is to continue the Company's current practice of designing its standard rates to accommodate those needs.

### **4. Block Rates**

Finally, given the circumstances of this case the Commission is persuaded of the merits of adopting a five-block rate design modeled on the system adopted in CenterPoint Energy's last rate case<sup>56</sup> as recommended by the Energy CENTS Coalition and the Administrative Law Judge.

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<sup>56</sup> *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 13-15.

This system is designed to reduce electric bills for those with the lowest energy consumption while also providing an incentive for conservation by those with high rates of consumption.<sup>57</sup> This design will eliminate the Company's current practice of providing a residential ratepayer with 50 kWh each month at no incremental charge. But the broader range of rate blocks will enable the Company to provide a discount for a larger number of kWh each month, while providing more rate blocks for recouping the cost of these discounts from high-volume customers.

As previously noted, parties raised a variety of concerns about this proposal. They argued that the new rate design is unfamiliar and untested. They argued that the new rate design would provoke needless customer confusion. And they argued that the new rate design would have the effect of shifting costs from households with low levels of energy consumption to households with high levels of consumption – including some high-use, low-income households.

The OES correctly observes that this is an uncommon rate design for Minnesota. The record identifies only one other instance in which a five-block rate design was implemented: as part of an ongoing pilot program involving CenterPoint Energy. The novelty of this rate design did not deter the Commission from approving it for CenterPoint, and it will not deter the Commission from approving it today. But prudence prompts the Commission to regard this new rate design as a pilot program, warranting ongoing oversight. Consequently the Commission will direct the Company to evaluate the effectiveness of this pilot program on an annual basis, and to offer a recommendation in its next rate case whether to continue the use of this rate design.

Given that the Company's residential ratepayers have had years of experience with rate blocks, the Commission does not foresee substantial customer confusion resulting from two more blocks. Moreover, the potential for confusion can be managed with the appropriate communications that accompany any general rate increase.

Finally, while the block rates it approves today may shift costs to higher-usage households, the Commission notes that this was a common feature of every rate design proposed in this proceeding. Moreover, as the Energy CENTS Coalition argued, there are more potential opportunities for aiding a household with high usage than one with low usage.

To complement the five-block rate design, therefore, the Commission will direct the Company to develop a program targeted to the needs of high-usage, low income households. Energy utilities and state agencies have gained increasing familiarity with these programs. Specifically, the Commission will direct the Company to develop a program to address the needs of its low-income, high-usage customers modeled on Xcel's program, including its Power On program. In particular, the Commission will direct the Company to propose compliance reporting similar to the reporting Xcel provides regarding its low-income discount program.<sup>58</sup> The Commission will provide the utility with 90 days in which to make its filing.

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<sup>57</sup> *Id.*

<sup>58</sup> *In the Matter of a Petition to Revise Xcel's Low-Income Discount Program to Comply with Modifications in Minnesota Statutes § 216B.16, Subdivision 14*, Docket No. E-002/M-04-1956, Order Approving Program Changes (April 26, 2005); Order Adopting Additional Reporting Requirements for Electric Low-Income Discount Program (September 16, 2010).

## **XXIII. Large Power Rate Design Stipulation and Settlement**

### **A. Introduction**

Large industrial customers pose special planning challenges for an electric utility because they can require a lot of power and their demand may fluctuate radically due to changes in market conditions for the products these customers produce. A utility faces the need to build plant to serve the customer's peak demand, but without the assurance that the customer will continue consuming power – and providing revenues – to pay for that plant.

One means of managing this challenge is to charge each large customer not only based on the amount of energy consumed but also based on the customer's peak level of demand. To guard against the risk that a large industrial customer would cease taking service – and paying bills – altogether, the utility may negotiate long-term contracts with customers providing for the customer to make certain minimum payments in any event. Consistent with this practice, Minnesota Power has entered into multi-year Electric Service Agreements with its Large Power taconite mining and forest products customers to require certain minimum payments. Under the terms of “minimum firm demand” or “take-or-pay” clauses, a Large Power customer pays a minimum charge based on 20% – 25% of the “firm demand level” that it designates three times a year, and also may pay higher charges if it takes power in excess of its nominated level.

The structure of these agreements give a customer an incentive to choose a low firm demand level during periods of low activity, and to increase its firm demand level shortly before periods of increased activity. This strategic practice, however, defeats the purpose of having a minimum payment clause because Minnesota Power cannot abruptly adjust its level of plant investment to match these changes in minimum demand payments.

### **B. Positions of the Parties**

As part of its rate case proposal, the Company proposed changing its tariff to require all Large Power customers to make take-or-pay payments calculated on the basis of no less than 50% of the customer's firm demand. In addition, the Company proposed establishing a new charge for customers that make large, abrupt increases in their firm demand levels.

The Large Power Intervenors opposed both proposals. They argued that the new terms would impose a needlessly restrictive uniformity on Large Power customers that failed to reflect each customer's unique circumstance. Moreover, they argued that the new terms would deprive customers of the benefits of the bargains they struck with Minnesota Power when then entered into their current Electric Service Agreements.

Ultimately the Company and the Large Power Intervenors arrived at an agreement whereby Minnesota Power would withdraw its proposal to impose its proposed changes by tariff. Instead, Minnesota Power and the Large Power customers would renegotiate these provisions as each Electric Service Agreement expires, and submit their revised agreements for Commission review. The OES found this proposal acceptable.

But the OAG-RUD continued to support the Company's initial proposal establishing a minimum take-or-pay obligation. Building plant to serve customers with radically fluctuating demand is inherently risky, the OAG-RUD argued, and the Company's proposal created a mechanism to place the cost of that risk on the customers that create it. Without this mechanism, the OAG-RUD warned, these risks will be transferred to other customers.

### **C. Recommendation of the Administrative Law Judge**

The Administrative Law Judge concluded that the Company had simply identified an alternate means for resolving problems in the Large Power class rate design. Finding this alternative reasonable, the Administrative Law Judge recommended that the Commission approve it.

### **D. Commission Action**

The Company – and RUD-OAG -- have identified a legitimate basis for concern with the design of Large Power rates. But there is more than one way to resolve these concerns. As the Company renegotiates its Electric Service Agreements and files them for Commission review, all parties will have the opportunity to address these issues in a context that can also address the particular needs of each Large Power customer. Consequently the Commission concurs with the Administrative Law Judge and adopts her findings, conclusions, and recommendations on this issue.

## **XXIV. CIP Expenses and CIP Rate Design**

### **A. Introduction**

Minn. Stat. § 216B.241 directs energy utilities to engage in Conservation Improvement Programs (CIP) designed to reduce the amount of energy consumed, or reduce the amount of energy consumed per unit of production (that is, to increase energy efficiency). Utilities may recover the prudently-incurred cost of these programs from their ratepayers.

### **B. Positions of the Parties**

The Company and the OES agreed that the Company should be entitled to recover \$4.6 million in CIP expenses incurred for conservation programs.

The Company had previously allocated these costs among its revenue classes in proportion to the revenues generated by each class. In this case, however, the Company and OES agreed that the costs should be allocated to customer classes in proportion to the energy consumed by each class, and then allocated within the class on the basis of each customer's energy consumption. This change has the effect of allocating more costs to the Large Power class, and to the largest members within that class.

The Minnesota Chamber of Commerce objected to the allocation, arguing that it represented yet another unwarranted cost shift to the industrial sector.

### **C. Recommendation of the Administrative Law Judge**

Finding the positions of the Company and the OES to be reasonable, the Administrative Law Judge recommended approval.

### **D. Commission Action**

There are many possible ways to allocate costs among customers and customer classes. CIP costs are incurred to encourage energy conservation. The choice to allocate those costs in proportion to energy consumption is entirely reasonable and consistent with the allocations used by other Minnesota utilities.

The Commission concurs in the Administrative Law Judge's conclusions and adopts her findings, conclusions, and recommendations on this issue. Specifically, the Commission will approve the Company's request for recovery of \$4.6 million in Conservation Improvement Program expenses, along with allocation of CIP expenses on a per-unit-of-energy basis and a rate design using a per-kWh rate instead of the current percentage of revenue methodology.

### **XXV. Housekeeping and Compliance Issues**

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. Minnesota Power is entitled to increase Minnesota jurisdictional revenues by \$53,530,424 to produce jurisdictional total retail related revenue of \$661,768,729 for the test year ending December 31, 2010.
2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth herein.
3. Within 30 days of the date of this Order, the Company shall file with the Commission, for its review and approval, and shall serve on all parties to this proceeding, a compliance filing implementing the decisions made herein and containing at least all of 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. 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 all the items set forth below:
  - a. Total revenue by customer class.
  - b. Total number of customers, the customer charge and total customer charge revenue by customer class.
  - c. For each customer class, the total number of energy and demand related billing units, the per unit energy and demand related cost of energy, and the total energy and demand related sales revenue.
- B. Revised tariff sheets incorporating authorized rate design decisions.
- C. Proposed customer notices explaining the final rates, the monthly basic service charge, and the expanded inclining block energy charges.
- D. A revised base cost of energy, supporting schedules, and revised fuel adjustment tariffs to be in effect on the date final rates are implemented.
- E. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.
- F. A schedule detailing the Conservation Improvement Program (CIP) tracker balance at the beginning of interim rates, the revenues (Conservation Cost Recovery Charge 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.
4. Comments on the Company's compliance filings shall be filed within 30 days of the date filed. Comments on the proposed customer notice are not necessary.
5. The Commission accepts the provisions of the Multi-Party Stipulation and Settlement permitting the capitalization of the Boswell 3 tracker balance, modified to capitalize the actual tracker balance reflecting recoveries during the interim rate period. Within 30 days of the date of this order, the Company shall make a compliance filing showing the tracker account activity starting on November 1, 2009 and detailing the amount capitalized.
6. Notwithstanding the Commission's acceptance of the Multi-Party Stipulation and Settlement, including the provisions regarding Margin Impact Analysis Filings and subsequent rate-adjustment petitions, any person or party that may participate in a rate case may file a rate-adjustment petition based on any Margin Impact Analysis filed under the Multi-Party Stipulation and Settlement.
7. Notwithstanding the provisions of the preceding ordering paragraph, the question of whether a rate-adjustment petition filed under the Multi-Party Stipulation and Settlement would constitute a petition for impermissible single-issue ratemaking is not currently before the Commission, and the Commission makes no determination on that issue in this order.

8. The Company shall amortize the rate case expenses authorized for recovery herein over a three-year period and shall defer amounts recovered for rate case expense after the three-year amortization period for consideration in the Company's next rate case.
9. The Company shall continue to record and track all incentive compensation costs recovered in rates and all incentive compensation amounts paid to employees, to permit the refund of any over-recovered amounts to ratepayers.
10. The Company shall adjust its interest synchronization and cash working capital as necessary to reflect the decisions made in this rate case.
11. In its next rate case filing, the Company shall address and provide testimony on the issue of whether it is reasonable for ratepayers to continue to bear the costs of Other Post-Employment Benefits expenses.
12. In its next rate case filing, the Company shall provide (a) a list showing, for every non-bargaining employee, the employee's job title/position, base salary, bonus and incentives, and other compensation; and (b) salary surveys and analyses linking each listed employee with employees holding comparable positions in other businesses.
13. In its next rate case filing, the Company shall include an itemized schedule of employee recognition expenses with the other itemized schedules required under Minn. Stat. § 216B.16, subd. 17.
14. In its next rate case filing, the Company shall include a cost/benefit analysis on the use of corporate aircraft.
15. In its next rate case filing, the Company shall provide testimony about its efforts to control costs. It shall list all cost reductions made, state which cost reductions are permanent, and quantify total cost savings.
16. The Company shall develop written policies on including in rates the costs of employee travel, lodging, and meal expenses and shall implement an employee expense compliance plan to ensure that these policies are followed. The Company shall report on these efforts in its next rate case filing.
17. The Company shall account for future lobbying expenses by assigning both employee and contract lobbying expenses to FERC Account 426.4 and excluding this category from operating and maintenance expenses recovered from ratepayers.
18. The Company shall continue working with the Office of Energy Security on improving the electronic linkage between its Class Cost of Service Study, its forecasting processes, and its revenue models.
19. In future rate case filings, the Company shall provide all data used in its test year sales forecasts at least 30 days before filing the rate case.
20. In future rate case filings, the Company shall conduct any Class Cost of Service Study (CCOSS) by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.

21. In its next rate case filing, the Company shall provide a description and an explanation of each classification and allocation method used in its Class Cost of Service Study and justify why that method is appropriate and superior to alternative methods considered.
22. In its next rate case filing, the Company shall provide a marginal energy cost study.
23. Minnesota Power shall start a new load research study by the end of 2011.
24. Within 30 days of the date of this order, the Company shall develop and propose a time-of-use tariff for the Large Light and Power customer class.
25. Within 90 days of the date of this order, the Company shall develop and propose a program to address the needs of low-income, high-usage residential customers modeled on Xcel's program, including its Power On program. This program shall include regular compliance reports similar to those Xcel is required to make as part of its electric utility's low income discount program.
26. In its next rate case filing, the Company shall recommend whether to continue the pilot Residential General service rate design.
27. The Company shall make an annual filing evaluating the effectiveness of the pilot Residential General service rate design.
28. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar  
Executive Secretary



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