BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota

ISSUE DATE: September 3, 2013

DOCKET NO. E-002/GR-12-961

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 2, 2012, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed this general rate case seeking an annual rate increase of $285,476,000, or approximately 10.7%. The filing included a proposed interim rate schedule.

On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated December 20, 2012.[1]

On December 26, 2012, the Commission issued three orders in this case:

- an order finding the rate case filing substantially complete, requiring supplemental filings on capital structure and cost-of-capital issues, and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

[1] *In the Matter of Xcel Energy's Request for Approval of a New Base Cost of Energy*, E-002/MR-12-1150, order dated December 20, 2012.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Northern States Power Company d/b/a Xcel Energy, represented by Aakash H. Chandarana, James P. Johnson, Kari L. Valley, Alison C. Archer, James R. Denniston, and Mara N. Koeller, all of Xcel Energy Services, Inc., and Richard J. Johnson, Moss & Barnett.

- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Julia E. Anderson and Linda S. Jensen, Assistant Attorneys General.

- Antitrust and Utilities Division of the Office of the Attorney General (the OAG), represented by Ronald M. Giteck, Ian Dobson, and Christopher Shaw, Assistant Attorneys General.

- Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; and USG Interiors LLC (collectively, the "Xcel Large Industrials" or "XLI"), represented by Andrew P. Moratzka, Stoel Rives LLP.

- Minnesota Chamber of Commerce (the Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.

- Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy (collectively, "the Environmental Intervenors"), represented by Kevin Reuther, Minnesota Center for Environmental Advocacy.

- Suburban Rate Authority ("SRA"), represented by James M. Strommen, Kennedy & Graven, Chartered.

- Energy CENTS Coalition, represented by its Executive Director, Pam Marshall.

- The Commercial Group, an ad hoc association of Xcel's large commercial customers, identified as including Macy's, Inc.; JC Penney Corporation, Inc.; Sam's West, Inc.; and Wal-Mart Stores, Inc.; represented by Alan R. Jenkins, Jenkins at Law, LLC.

- U.S. Energy Services, Inc., on its own behalf and on behalf of an ad hoc group of its industrial, commercial, and institutional customers (collectively, the "ICI Group"), represented by Brian M. Meloy, Leonard Street and Deinard.

III. Proceedings Before the Administrative Law Judge

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

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on April 18–19 and 22–24, 2013. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact.

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

- Minneapolis, March 4, 2013 – 1:00 p.m. and 7:00 p.m.
- Woodbury, March 7 – 7:00 p.m.
- Saint Paul, March 8 – 1:00 p.m.
- Mankato, March 18 – 7:00 p.m.
- Eden Prairie, March 19 – 7:00 p.m.
- St. Cloud, March 22 – 1:00 p.m.

IV. Public Comments

The Administrative Law Judge held seven public hearings; 121 members of the public attended, and 38 spoke. Representatives of Xcel, the Department, and the Commission also attended, to answer questions and receive public input. Over 1,300 members of the public submitted written comments.

Commenting members of the public were overwhelmingly opposed to the rate increase proposed by the Company. The objections raised most frequently were that the increase would cause hardship for low-income households; that customers' conservation efforts were not being rewarded and might therefore be discouraged; that the Company was not controlling costs sufficiently, particularly in the area of executive compensation; and that it was reasonable for the Company to scale back its profit expectations in challenging economic times.

A summary of all public comments is attached to the Administrative Law Judge's Report as Attachment B.

V. Proceedings Before the Commission

On July 5, 2013, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law, and Recommendations (the ALJ's Report).

The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, the Xcel Large Industrials, the Chamber, the Environmental Intervenors, the SRA, and the Energy CENTS Coalition.

On August 6 and August 8, 2013, the Commission heard oral argument from and asked questions of the parties. On August 8, 2013, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order, approving an annual rate increase of $102,797,000.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

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

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the 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

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

[3] *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, 411 (Minn. 1998).

> 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.[4]

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.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

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 Court of Appeals explained, quoting the Supreme Court:

> 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."[7]

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[4] *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) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

[7] *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) (citation omitted).

II. Summary of the Issues

Some contested issues were largely resolved by the time of oral argument; others remained in dispute. Each one was fully considered. In some instances, the Commission accepted the Administrative Law Judge's recommendation without discussion. Other issues, and the Commissioners' determinations on them, are synopsized below.

Financial Issues

- ***Cost Overruns in Life-Cycle Management/Extended Power Uprate Project at Monticello Nuclear Plant –*** In February 2009, the Company obtained a certificate of need for extensive construction and retrofitting at its Monticello nuclear plant to increase the plant's life by 20 years and its generating capacity by 71 megawatts. Project costs now exceed initial estimates by some $266,700,000, and the plant is not yet operating at the higher generating capacity. Parties challenged including these cost overruns in rates, questioning the Company's prudence in managing project costs and questioning how much of the project meets the "used and useful" or "plant in service" standard for rate recovery during the 2013 test year.

The Administrative Law Judge recommended placing in CWIP (Construction Work in Progress) accounts all costs of the Power Uprate Project, and the portion of the costs of the Life Cycle Management Project incurred to accommodate the Power Uprate, pending future examination of their prudence, reasonableness, and in-service status.

The Commission concurs in part, as explained below.

- ***Direct Costs of Idled Sherco 3 Generator –*** In November 2011, an accident at the Company's largest generator forced its shutdown. Damage to the generator was massive, and it remains shut down. The Company seeks rate recovery of some $35,500,000 in plant costs incurred in 2013—including depreciation expense, property taxes, payroll taxes, fuel handling, insurance, operation and maintenance costs, rate of return, and a tax gross-up—and states that the plant will be back in service before the end of the year. Parties challenged the claim that the plant will be in service by the end of the year and urged disallowance of rate recovery of some or all of these costs on grounds that the plant does not meet the "used and useful" or "plant in service" standard for rate recovery.

The Administrative Law Judge found it proper to balance ratepayers' interests in rate relief with the Company's interests in cost recovery. She recommended deferring these costs and amortizing them over the remaining life of the plant, beginning in 2014.

The Commission concurs in part, as explained below.

- ***Costs of Cancelled Power Uprate Project at Prairie Island Nuclear Plant –*** In February 2013, after an on-the-record proceeding, the Commission issued an order concurring in the Company's determination that it should cancel the extended power uprate project it had begun at its Prairie Island nuclear power plant. The Company placed the costs of the cancelled project, some $64,000,000, in a regulatory asset account, intending to seek rate recovery later. Parties asked the Commission to find that the Company's failure to seek rate recovery in *this* rate case bars future requests for recovery.

The Administrative Law Judge found that this issue was not ripe for decision and recommended taking no action on it.

The Commission concurs that the record is insufficient to take action at this time.

The parties disagreed about the Company's obligation to specifically request the Commission's approval for deferred accounting of the cancelled project's costs, and whether its failure to make that request barred the Company's recovery of those costs. The Commission's Order in Docket No. E-002/CN-08-509, issued on February 27, 2013, approved termination of the project but did not offer an opinion on whether cost recovery would be permitted, allowing the Company to address the issues in a rate case. The Order stated: "Nor does the decision address the prudence of Xcel's investments or the recovery of those costs; those judgments may be made in the context of Xcel's rate case."

At oral argument, both the Company and the Department asserted that the timing of the February order precluded a thorough examination of the project costs in this rate case; no party argued to the contrary.

Because the commission initially approved the Certificate of Need for the power uprate project and subsequently confirmed the Company's decision to abandon the project, it was well aware that the costs incurred would require careful review in a future proceeding and expressed that view in its February Order. Thus, the Commission concurs with the Administrative Law Judge that the record is not sufficient to reach a decision about the prudency of the costs at this time. But the project costs should receive careful review to determine which costs, if any, should be borne by the ratepayers. The Company will be required to fully justify its request for rate reimbursement of project costs in its next rate case.

- ***Pension Costs –*** The Company seeks rate recovery of some $27,934,000 in qualified pension expense and some $4,240,000 in corresponding capital costs; it included in these costs an amortized portion of the market losses its pension accounts sustained in the 2008 economic downturn. It also included the costs of one non-qualified pension plan, the Restoration Plan, which compensates its top-earning executives if portions of their pension benefits are denied qualified-pension status treatment under IRS rules. The Department challenged the inclusion of Restoration Plan costs and the 2008 market losses as unnecessary. It also challenged the discount rate used to convert future liabilities to present value as too low in relation to expected earnings, the earnings projections as unsubstantiated, and future wage projections as too high.

The Administrative Law Judge found that the Company's future wage projections were reasonable but that the challenged discount rate and earnings projections were neither adequately supported nor adequately correlated. She also found that it was reasonable for the Company to recover its 2008 pension fund losses through its proposed amortization plan. She recommended disallowance of Restoration Plan costs.

The Commission concurs based on the record in this case, but will set additional reporting requirements for the next rate case and will clarify that the determination that the 2008 market loss may be included as a cost is limited to this proceeding and that the Company will earn no return on the unamortized asset loss balances.

- ***Sales Forecast –*** Parties challenged many of the factual assumptions underlying the Company's sales forecast, including its projections on customer counts, energy prices, usage by commercial and industrial customers, and the impact of demand-side management programs.

The Administrative Law Judge weighed the evidence and concluded that the Company forecast set energy prices, customer counts, sales to Large Commercial and Industrial customers, and conservation-related sales losses too high.

The Commission concurs in large part, as explained below.

- ***Nobles Wind Farm Costs –*** The Company seeks rate recovery of some $5,600,000 in capital costs not included in the cost estimates in its 2008 petition for approval of the Nobles Wind Farm as a Renewable Energy Standards project. Parties challenged recovery on grounds of reasonableness. They also argued that, since the wind farm was a competitively bid project, costs should be limited to the amount of the winning bid.

The Administrative Law Judge found that the costs were reasonable, but recommended denying rate recovery as time-barred under the terms of an earlier Commission order. In the alternative, she recommended permitting recovery of, but not on, the Company's $5,600,000 investment, using a ten-year amortization period.

The Commission adopts a modified version of her alternative recommendation, as explained below.

- ***Depreciation Reserve Surplus –*** The Company's depreciation accounts show that its depreciation reserve exceeds its theoretical depreciation reserve by approximately $265,000,000 for its transmission, distribution, and general assets and $219,000,000 for its production assets, especially its nuclear generating units. Parties urged that these surpluses be liquidated in the form of rate reductions over the next five years.

The Administrative Law Judge found that the preponderance of the evidence established that there was no surplus depreciation reserve for the Company's production assets. She confirmed the surplus in the transmission, distribution, and general asset accounts. As a remedy, she recommended amortizing this surplus over the average remaining lives of the assets, 33.47 years; alternatively, she recommended amortizing the surplus over 15 years. She also recommended requiring the Company to work with stakeholders to examine the issue further.

The Commission adopts a modified version of her alternative recommendation, as explained below.

- ***Accounting Treatment of Transmission Studies –*** The Department challenged the Company's inclusion of certain transmission study costs as operating expenses, claiming that 50% of those costs should be capitalized as part of the cost of future capital projects.

The Administrative Law Judge found that the Company had examined each study before expensing it and appropriately determined that it should be expensed, not capitalized. She recommended accepting this determination.

The Commission concurs.

- ***Base Salary Increases for Non-Bargaining Employees –*** The Department challenged the Company's proposal to set test-year salaries for non-bargaining employees at 2012 actual levels, minus merit increases, plus a 2.32% salary increase. The Department recommended setting those salaries based on data from the Company's 2008 rate case, with inflation adjustments based on projected escalation factors for 2010, 2011, and 2013, developed in a study by the economic forecasting firm IHS Global Insight.

The Administrative Law Judge found that the Company had demonstrated that its proposed salary expense for non-bargaining employees was reasonable and prudent.

The Commission concurs.

- ***Incentive Compensation –*** The Company included incentive compensation costs of $20,700,000 in test-year expense. Incentive compensation is based on the performance of the individual, the business unit, and the Company in meeting identified objectives, including customer satisfaction, reliability, safety, and environmental responsibility. Exempt employees not represented by a bargaining unit are eligible to receive incentive compensation. Parties challenged these costs as excessive, inadequately supported, and insufficiently linked to cost containment benchmarks.

The Administrative Law Judge found that the Company had demonstrated the reasonableness and prudence of providing Incentive Compensation or an equivalent increase in base salary.

The Commission concurs, but will require further Company evaluation of its Incentive Compensation program in its next rate case.

- ***Carrying Charge/Rate of Return on Nuclear Refueling Outage Costs –*** Since the conclusion of its 2008 rate case, the Company has been deferring and amortizing its nuclear refueling outage costs; the Commission approved this cost treatment to ensure greater accuracy in cost recovery, to match more closely the times these costs are incurred with the time of their recovery, and to avoid substantial fluctuations in these costs between rate cases. Parties challenged the Company's practice of including unamortized costs in rate base and charging or crediting ratepayers its rate of return on unamortized amounts.

The Administrative Law Judge recommended reducing the carrying charge on these costs and suggested using the short-term cost of debt or the prime interest rate.

The Commission disagrees, as explained below.

- ***Construction Work in Progress and Allowance for Funds Used During Construction (CWIP and AFUDC) –*** AFUDC is an accounting device used to permit utilities to recover the cost of capital used during construction. Capital costs incurred during construction are placed in rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant under construction goes into service. Parties claimed the Company misuses CWIP/AFUDC by including short-term and low-cost projects. They also claimed that CWIP is inappropriate in principle because it shifts shareholders' risks to ratepayers and forces ratepayers to bear costs for which they receive no current benefit.

The Administrative Law Judge found that CWIP and AFUDC were permissible under Minnesota law, Federal Energy Regulatory Commission regulations, and past Commission practice; she also found that the Company's use of these accounting devices was appropriate.

The Commission will permit the proposed inclusion of CWIP and AFUDC in this case but will require a more detailed explanation of the Company's CWIP and AFUDC practices in its next rate case filing.

- ***Other Operating Revenues –*** "Other operating revenues" is a line item reflecting miscellaneous revenues that reduce the Company's revenue requirement. The Company used a three-year historical average to set its test-year amount, as the Department recommended. The Department also proposed adjusting this line item to include two revenue categories the Company had excluded: nuclear outage deferred revenue amortization and depreciation change.

The Administrative Law Judge found that both items had been accounted for earlier or elsewhere and should not be added to "other operating revenues."

The Commission concurs.

- ***Additional Energy Assistance Funding –*** There was general agreement to add $3,200,000 to existing funding for Xcel's energy-assistance program for low-income customers, PowerON. Parties differed on whether to include the full increase in this test year, given the end-of-year timing; whether Xcel itself should fund some portion of the increase; whether some portion of the increase should be assumed to be offset by reduced bad debt expense; and how the increase should be funded (e.g., through base rates, existing surcharge, late payment fees).

The Administrative Law Judge recommended including the full increase in this test year, found that rate recovery was reasonable, and recommended building the $3,200,000 test-year amount into base rates.

The Commission concurs in large part, as explained below.

- ***FERC 921 (Office Supplies and Expenses) Fluctuations –*** FERC (Federal Energy Regulatory Commission) account 921 is used to record non-labor administrative and general expenses, such as those related to information technology, facility upkeep, human resources, safety programs, customer care, and Corporate Secretary functions. The Department noted that these costs have fluctuated over the past several years and that 2013 test-year costs exceed 2012 actual costs by some $1,500,000. The Department therefore recommended that these costs be set using a three-year historical average.

The Administrative Law Judge found that the Company had demonstrated the reasonableness and prudence of these test-year costs but concurred with the Department that the Company should provide more detailed reporting on these costs in its next rate case.

The Commission concurs.

- ***Corporate Aviation Expense –*** The Company included in test-year costs $756,000 in corporate aviation expense, 50% of its total corporate aviation costs. The Office of the Attorney

General recommended reducing that expense to $203,111, which it calculated as the cost of commercial air fare for the trips included in the expense.

The Administrative Law Judge found that the Company had demonstrated the reasonableness of this expense in terms of employee time savings and increased productivity.

The Commission concurs but will direct the Company to include more detailed data about corporate jet trips in its next rate case.

- ***Interest Rate on Interim Rate Refund –*** Commission rules require the Company to refund to ratepayers the difference between interim rates and final rates, with interest calculated at the prime rate. Parties recommended varying the rule and setting the interest rate at the Company's authorized rate of return instead of the 3.25% prime rate.

The Administrative Law Judge found that the parties had failed to address one of the three legal requirements for a variance, but that the Commission could reasonably choose to vary the rule on its own motion or to impose a carrying charge independent of the refund distributed to ratepayers. The Administrative Law Judge also noted that there were other alternatives to the prime rate, such as the cost of short-term debt.

The Commission concurs in part, as explained below.

- ***Interim Rates in the Company's Next Rate Case –*** The Office of the Attorney General recommended determining that interim rates in the Company's next rate case, which it states it will file in November, will be the final rates set in this case.

The Administrative Law Judge found that it would be premature to make that determination before the rate case was filed.

The Commission concurs.

Cost of Capital Issues

Rate of Return on Equity – The awarded Return on Equity (ROE) significantly affects the overall revenue requirement and the Company's ability to attract capital. As in other rate cases, its significance is reflected in the careful attention paid to it by the witnesses, the parties and the Administrative Law Judge. It was addressed again in the parties' exceptions to the Administrative Law Judge's report and at oral argument.

The Company and the Department conducted comprehensive analyses of the return on equity required to enable the Company to (a) maintain its credit rating and financial integrity; (b) attract the capital required for reasonable and prudent capital expenditures; and (c) provide investors with returns commensurate with the returns on other investments of comparable risk. The Company advocated a return on equity of 10.60%; the Department advocated a return on equity of 9.83%. ICI asserted that the Commission either maintain the current ROE of 10.37% or adopt the Department's recommended ROE of 9.83%. The Commercial Group argued that the ROE be adjusted downward to the low end of any reasonable range, below the 9.83% recommended by the Department.

After extensive analysis, the Administrative Law Judge recommended adopting the Department's recommended 9.83% return on equity. The Company pursued its argument in its exceptions and oral argument that its recommended ROE of 10.25% was more reasonable.

The Commission concurs with the Administrative Law Judge that the Department's position is best supported by the record and falls within the range of the Company's discounted cash flow analysis as filed in its rebuttal testimony.

Rate Design and Class Cost of Service Issues

- ***Inverted Block Rates for the Residential Customer Class –*** Parties proposed establishing a five-tier, inverted block rate structure for the residential customer class. Under the proposal, per-unit energy rates would rise as usage passed four thresholds: 500 kWh; 750 kWh; 1,000 kWh; and 1,500 kWh. Units of energy consumed below each threshold would be priced at that threshold's rate. The proposal was designed to reduce energy bills for low-usage, low-income households and to promote conservation.

The Administrative Law Judge found that the proposal at issue may have unintended negative consequences on low-income customers and may be less effective than other means of meeting these goals. ~~and~~ She recommended that it not be implemented at this time.

The Commission concurs.

- ***Competitive Response Rider –*** The Company proposed to combine two current rate riders that offer discounted energy prices to certain large customers into a new Competitive Response Rider. The stated purpose of the rider is to attract and retain large customers who have competitive alternatives to Xcel service, on grounds that they contribute to the recovery of fixed costs that would otherwise be spread over a smaller body of ratepayers. Parties challenged the language of the rider as overly broad, and the rider itself as not benefitting all customer classes.

The Administrative Law Judge found that the rider, properly drafted, was reasonably likely to achieve its goals and recommended its approval with the Department's modifications. Prior to the Commission's decision, the Company acceded to the Department's revisions.

The Commission concurs with the Administrative Law Judge.

- ***Business Incentive and Sustainability Rider –*** The Company proposed a new Business Incentive and Sustainability Rider to attract new commercial and industrial customers and to encourage existing large customers to expand operations. The rider would offer fixed demand discounts for a fixed term not to exceed five years. Participants would be required to make significant capital investments and to undergo operational energy audits. Parties challenged the rider as not benefitting all customer classes and as inconsistent with state energy conservation policies.

The Administrative Law Judge found that the rider, refined in response to the analysis of the parties, would benefit all ratepayers through the fixed-cost contributions from the new load and that the mandatory energy audit would encourage conservation. She recommended its approval.

The Commission concurs.

- ***Class Revenue Apportionment –*** The Company proposed to shift the percentage of the revenue requirement built into the rates of each customer class to more closely match the cost of service attributed to each customer class under its Class Cost of Service Study. Parties challenged this proposal as giving too much or too little credibility to the Class Cost of Service Study, which is acknowledged to be imprecise. They also differed over the importance the Commission should place on non-cost factors—such as administrative efficiency, rate continuity, social utility, and public acceptance—in apportioning the revenue requirement between the customer classes.

The Administrative Law Judge recommended adopting a class revenue apportionment that moved rates closer to the cost of service in the Class Cost of Service Study, without moving them directly to the costs derived in the Study.

The Commission concurs.

- ***Customer Charges –*** Customer charges are designed to recover the fixed costs of serving customers regardless of how much electricity they use. These costs cover business functions such as billing, meter-reading, and building and maintaining infrastructure. The Company's Class Cost of Service study indicates that these fixed costs exceed customer charges for the residential and small general service classes; the Company proposed to move these customer charges closer to cost as defined in that study. Parties challenged the accuracy of the Class Cost of Service Study and the weight it should be given. Parties also argued that the rate increases would result in rate shock and would work at cross-purposes with the statutory mandate to set rates to encourage conservation.

The Administrative Law Judge recommended reducing the increases proposed by the Company while moving Customer Charges closer to the fixed costs indicated in the Class Cost of Service Study.

The Commission will further reduce the Customer Charges proposed by the Company, as explained below.

- ***Coincident Peak Billing –***The Chamber of Commerce proposed that the Commission require the Company to aggregate the meter readings and resulting bills of multi-meter customers to calculate demand charges based on the aggregate demand of all meters. The Company claimed that this would be an expensive undertaking that should not be charged to the general body of ratepayers.

The Administrative Law Judge found that the proposal was not sufficiently developed, especially in regard to cost implications, to demonstrate that it would result in reasonable rates. She recommended not adopting it in this case.

The Commission concurs.

- ***Interruptible Rates –*** Customers who take interruptible service agree to have their service interrupted when called upon by the Company, or face high penalties. The utility and its ratepayers benefit from interruptible load by not having to build or acquire the additional generation to serve it and by lowering the firm load subject to the reserve margin requirements of the Midcontinent Independent System Operator. The Company sets interruptible rate credits at the

lowest level it believes will attract enough interruptible load to meet short-term load-shedding needs and permit longer-term planning. The Chamber of Commerce argued that interruptible credits should be priced at the cost of a peaking plant generating the shed load and that the cost of interruptible credits should be borne entirely by firm load, not included in the base rates interruptible customers pay.

The Administrative Law Judge found that there was no reason to price interruptible credits above the amount needed to attract and maintain sufficient interruptible load, that all ratepayers benefit from the Company's current success in meeting that goal, and that rates can be adjusted in the future if necessary to continue meeting that goal.

The Commission concurs.

- ***End-of-Month Billing –*** The Company has over a million customers, all of whom are billed monthly. To manage billing operations and control costs, the Company staggers its billing cycles over the course of the month. The Chamber of Commerce pointed out that many large customers monitor their energy costs on a calendar-month basis, and that non-calendar-month billing cycles complicate this process. They asked the Commission to require the Company to provide end-of-month billing on request to any customer with total peak demand exceeding 1,000 KW.

The Administrative Law Judge found that the Company had not demonstrated that the Chamber's proposal was cost-prohibitive and recommended implementing it.

At oral argument the Chamber and the Company announced that they had reached agreement on this issue and jointly recommended not adopting the proposal. The Company has agreed to work with customers on billing solutions that can be accommodated without increasing costs.

The Commission will adopt the parties' agreement instead of the Administrative Law Judge's recommendation.

- ***Allocating the Conservation Cost Recovery Charge –*** Like all utilities, Xcel recovers its CIP (Conservation Improvement Program) costs in two ways – through a Conservation Cost Recovery Charge (CCRC) built into base rates and through a Conservation Cost Recovery Adjustment (CCRA), an automatic rate adjustment that trues up costs built into rates with actual costs. The Company calculates its CCRC using the percent-of-benefits method and its CCRA using the per-kWh method. The Department recommended requiring the Company to use the per-kWh method for both recovery mechanisms, arguing that the Commission has stated a preference for moving toward uniformity in these calculations and has required other utilities to use the per-kWh method for all forms of CIP-cost recovery.

The Administrative Law Judge found that the Company had supported its use of the percent-of-benefits method as reasonable and recommended permitting the Company to continue to use it.

The Commission will require the Company to use the per-kWh method to promote administrative and regulatory efficiency, as explained below.

- ***Allocating Other Operation and Maintenance Costs –*** With minor refinements, the Company proposed to continue its practice of allocating Other Operation and Maintenance Costs (production-plant costs other than fuel and purchased power) between energy and demand based on the allocations assigned to the underlying plant investment. Parties challenged this allocation on grounds that power-plant labor costs are more fixed than variable and more properly classified as demand-related than energy-related.

The Administrative Law Judge found that the Company had amply supported its allocation for purposes of this rate case but should provide a more detailed analysis of the issue in its next rate case.

The Commission concurs.

- ***Allocating Fixed Production Plant –*** The Company allocated the costs of its fixed production plant using the plant stratification method, which classifies and allocates fixed costs between energy and demand based on customer demand at peak times. This method allocates a portion of fixed costs to the energy component of costs and rates. Parties challenged this method as resulting in higher costs for large customers and urged that all fixed costs be allocated to demand.

The Administrative Law Judge found that the plant stratification method was reasonable and had long had the support of the Commission. She did not recommend requiring its abandonment.

The Commission concurs.

- ***Allocating Demand-Related Costs in Regard to Average and Excess Demand –*** Under the plant stratification method the Company uses to allocate fixed plant costs between energy and demand, the Company allocates class responsibility based on each class's contribution to system peak. Parties claimed that the Company should instead allocate responsibility based on each class's contribution to excess demand, i.e., demand above the system average, to avoid double-counting average demand.

The Administrative Law Judge found that the Company was properly applying its demand allocation methodology and was not double-counting average demand.

The Commission concurs.

- ***Use of Winter Peak in Allocating Capacity-Related Production Plant Costs –*** In past rate cases the Company's Class Cost of Service Study had allocated capacity-related production plant costs based on weighting of both the summer system coincident peak and the winter system coincident peak. The Company is clearly summer-peaking, but it used the weighting of the two peaks to recognize that the system was used in other seasons for reasons such as plant maintenance. Parties argued that proper cost allocation must be tied to cost-causation at the time the investment is incurred, not on how the resource may be used later. The Company agreed and changed its allocation to use summer peak only. The Office of the Attorney General claimed that the allocation method should reflect the actual use of the system, not just the reasons investments were made.

The Administrative Law Judge found the Company's revised allocation reasonable and recommended approving it.

The Commission concurs.

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held five days of evidentiary hearings and seven public hearings. She reviewed the testimony of 42 expert witnesses and examined over 188 hearing exhibits. She read some 1,300 written comments submitted by members of the public and took testimony at seven public hearings.

She received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. She made 908 findings of fact and conclusions of law and made recommendations on all stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that Report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below. And on a few issues it provides technical corrections and clarifications.

On all other issues, the Commission accepts, adopts, and incorporates her findings, conclusions, and recommendations.

IV. Summary of Commission Action

In its Briefing Papers, Commission staff recommended that the Company provide certain additional information in its next rate case. All parties had the opportunity to comment on these suggestions; the Company generally agreed to provide the requested information, and many of the staff recommendations were accepted by the Commission, as reflected in the Order.

On the following issues the Commission reaches conclusions different, at least in part, from those reached by the Administrative Law Judge:

- ***Cost Overruns in Life Cycle Management/Extended Power Uprate Project at Monticello Nuclear Plant***
- ***Direct Costs of Idled Sherco 3 Power Plant***
- ***Nobles Wind Farm Costs***
- ***Depreciation Reserve Surplus***
- ***Sales Forecast***
- ***Customer Charges***
- ***Additional Energy Assistance Funding***
- ***Interest Rate on Interim Rates Refund***
- ***Carrying Charge/Rate of Return on Nuclear Refueling Outage Costs***
- ***Allocating Conservation Improvement Program (CIP) Costs***

These issues are addressed below.

V. Cost Overruns in Life-Cycle Management/Extended Power Uprate Project at Monticello Nuclear Plant

A. Introduction

The Monticello nuclear power generating plant (Monticello) has been in operation since 1971 and was initially licensed to operate until 2010. In 2006, the Company obtained a license extension from the Nuclear Regulatory Commission (NRC) to continue operating the plant until 2030. In 2008, the Company requested a license amendment from the NRC to add approximately 71 MW of generating capacity to the plant, and applied for a Certificate of Need from this Commission to increase the generating capacity. The Company stated that it would achieve the additional 71 MW by increasing the amount of steam produced in the reactor, and by improving plant equipment, besides the reactor, that converts steam into electricity.

This Commission granted the Certificate of Need for the additional generating capacity at the Monticello plant.[8] The Company began a project to (a) extend the useful life of the plant (the Life-Cycle Management, or LCM, portion), and (b) increase its generating capacity (the Extended Power Uprate, or EPU, portion). In its Certificate of Need application, the Company estimated that $133,000,000 of the anticipated $320,000,000 project cost could be attributed to the EPU aspect of the project, or 41.6%.[9] It implemented the project in phases timed to correspond to scheduled refueling outages in 2009, 2011, and 2013.

The NRC has not yet authorized the Company to operate the Monticello plant at the higher EPU power level, and it is not certain when authorization will be granted. As a result, the Monticello plant is operating at its licensed 585 MW capacity using the improved equipment intended to accomplish both the LCM and the EPU aspects of the plant upgrade.

Additionally, the project experienced cost overruns. When it filed this rate case, the Company estimated that the LCM/EPU project would cost approximately $586,700,000, 83.3% higher than the cost anticipated in the Company's Certificate of Need filing. As this case proceeded the Company updated its estimate, but stated that it was limiting its request for recovery in the 2013 test year to no more than $586,700,000.

B. Positions of the Parties

Prior to Commission deliberations, the Chamber developed a proposal for treatment of Monticello LCM/EPU project costs for which the Company, the Xcel Large Industrials, and the Department each expressed support. The Chamber proposed that the Commission adopt a modified version of the ALJ's recommendation (described in detail below). The proposal generally excludes from the

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[8] *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Monticello Nuclear Generating Plant Extended Power Uprate*, Docket No. E-002/CN-08-185, Order Granting Certificate of Need and Accepting Environmental Assessment (January 8, 2009).

[9] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy, Inc. for a Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate*, Docket No. E-002/CN-08-185, Application for a Certificate of Need (February 15, 2008).

Company's rate base the project costs attributable to the EPU since the last rate case because that portion of the project was not "used and useful in rendering service to the public." The Chamber's proposed modifications would clarify the costs to be set aside and accounted for as "construction work in progress" (CWIP) for possible later recovery after the plant is licensed and operating at its uprated capacity.

In addition to the circumstances surrounding the pending NRC license to operate the plant at a higher generating capacity, the Department expressed concerns about the project's cost overruns. The Department argued in its reply brief at the close of the contested case proceeding that the Company had not adequately supported its request to recover $266,700,000 in project cost overruns.[10]

The Company asserted that the cost overruns were justified by NRC changes and delays, project design changes, and the discovery of previously unknown conditions at the plant. However, the Company indicated that it understands that, in conjunction with the Chamber's proposed resolution, all of the costs arising from the LCM/EPU project that it sought to include in its 2013 test year will be subject to a separate prudence review (described in greater detail below).

C. Recommendation of the Administrative Law Judge

The ALJ's findings and conclusions on this issue are addressed in paragraphs 49 – 85 of the report. Applying Minn. Stat. § 216B.16, the ALJ concluded that the Monticello LCM/EPU project is only used and useful in part. She determined that "the Monticello LCM/EPU capital project is 'in service' but only for LCM purposes. The equipment installed as part of the LCM/EPU project is being used to generate electricity at existing levels, not at the higher EPU level."[11] Accordingly, she concluded that "[b]ecause the plant is only generating power at existing levels, the EPU portion of the project is not 'in service' or 'used and useful.'"[12]

On the basis of these determinations, the ALJ recommended that the Commission adopt the Chamber's proposal. The Chamber proposed to hold a portion of the project's cost—limited to the portion reasonably attributable to the EPU aspect of the project—in CWIP, with an "allowance for funds used during construction" (AFUDC) offset.[13]

The ALJ concluded that the Chamber's proposal to hold 41.6% of the project in CWIP was reasonable, finding that a preponderance of the record evidence supported the conclusion that the percentage is a reasonable measure of the proportion of the project attributable to the EPU. The ALJ found that the Chamber's proposal "appropriately balances the interests of the ratepayers and the Company by recognizing that the ratepayers are not currently receiving the benefits of the EPU while also allowing the Company a future return on the EPU investment at the time when the plant is actually providing the additional power to ratepayers."

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[10] *Reply Brief of the Minnesota Department of Commerce*, 38.

[11] ALJ Report, ¶78.

[12] Id. at ¶82.

[13] CWIP and AFUDC are accounting designations under the Federal Energy Regulatory Commission's uniform system of accounts.

D. Commission Action

The Commission adopts the ALJ's analysis, findings, and conclusions found in paragraphs 49–85, with the clarifications explained below.

The Commission must consider the factors identified in Minn. Stat. § 216B.16, subd. 6, when determining what utility property should be included in the Company's rate base. Specifically, the statute requires that the Commission adequately provide for a utility to meet the cost of furnishing service, "including adequate provision for depreciation of its utility property used and useful in rendering service to the public."

The Commission agrees with the ALJ that only the LCM portion of the LCM/EPU project is used and useful. The Commission also agrees that 41.6% is the portion of the project properly attributable to the Extended Power Uprate, which cannot serve ratepayers until it is licensed by the NRC. Accordingly, that portion of the project should not earn a return before it is used and useful in providing service to ratepayers.

The Commission therefore determines that 41.6% of the LCM/EPU costs for 2011 and 2012 additions added to the rate base in this case, 41.6% of 2013 May plant addition costs, and 100% of Nuclear Regulatory Commission license fees should be moved from plant in-service to CWIP, as well as the related depreciation reserve, deferred taxes, depreciation expense, AFUDC, and any other applicable costs. The Company may be allowed to recover those costs in future rate cases once the EPU is in service, subject to the plant being used and useful and subject to a determination that the costs—including cost overruns—were prudent.

This approach best balances the interests of ratepayers, who are responsible for prudently incurred costs reasonably necessary to provide electric service, with the interests of shareholders, who earn a rate of return calculated to compensate them for assuming the business and operational risks associated with providing utility service. At the time of deliberations, the Company estimated that these adjustments would result in a reduction in the Company's revenue requirement of approximately $11,700,000.

The Commission shares the Department's concern regarding the project's significant cost overruns. The Commission will open a separate docket to investigate whether the Company's handling of the LCM/EPU project was prudent, and whether the Company's request for recovery of the Monticello LCM/EPU cost overruns is reasonable. The project proceeded as the record for this case was being developed, preventing a final determination of the project's prudence at this time. Investigating the project costs in a separate proceeding will promote development of a complete record on the issue, and allow the Commission to make a prudence determination outside the considerable time pressure involved in a rate case.

At the time of the Commission's deliberations, the Company did not oppose this approach to review of the LCM/EPU project.

Because the Commission will need specialized technical professional services to evaluate the project costs, pursuant to Minn. Stat. § 216B.62, subd. 8,[14] the Commission will direct the Executive Secretary, in consultation with the Department, to develop a proposal for the conduct of the investigation, including the scope, work plan, and retention of an expert, to develop a report and recommendation to the Commission.

VI. Direct Costs of Idled Sherco 3 Power Plant

A. Introduction

Sherco Unit 3 ("Sherco 3" or "the unit") is a 900-megawatt coal-fired generator first put into service in November 1987. It is the largest generator in Xcel's system.[15]

On November 19, 2011, Sherco 3 suffered a catastrophic failure. At that time, the generator was offline for a planned overhaul. Xcel completed the overhaul and started the unit. During the startup testing procedure, the turbine and generator instruments reported vibration significantly above normal levels, and the unit shut down. The vibration damaged many of the steam, oil, and hydrogen seals in the unit and started a fire. The malfunction was later determined to be the result of a manufacturer design defect.

Sherco 3's November 2011 failure precipitated an extended outage. Xcel decided to repair the unit. However, the damage proved more extensive than anticipated, and repair work was still underway in late 2012 when Xcel filed this case. Repairs and reassembly continued throughout the spring and summer of 2013, but the unit remained out of service in early August when the Commission met to consider Xcel's request for a rate increase. The Company currently predicts that the unit will return to service on or before September 30, 2013.

During the outage, ratepayers have continued to pay the rates set in Xcel's last rate case—rates premised on a functioning Sherco 3. As a result, Xcel over-recovered at least $14.1 million in 2011 and 2012 for Sherco 3 operation and maintenance (O&M) costs. In addition, ratepayers have had to pay significant amounts for replacement power as a result of the outage. As of October 2012, these additional costs stood at $22.7 million. They are expected to reach $40 million by the outage's end.

B. Positions of the Parties

1. Xcel

Xcel initially included the following direct costs for Sherco 3 in its test year: depreciation expense, property tax, payroll tax, fuel handling, insurance, O&M, emissions control chemicals, a return on rate base, and tax gross-up. According to the Department, Minnesota ratepayers' share of these costs would total approximately $39.9 million.

[14] Minn. Stat. § 216B.62, subd. 8, authorizes the Commission, in the course of carrying out an investigation of utility operations, practices, or policies to seek authority from the commissioner of management and budget to incur costs reasonably attributable to specialized technical professional investigative services necessary for the inquiry.

[15] Xcel owns approximately 59% of Sherco 3 (531 megawatts), and the Southern Minnesota Municipal Power Agency owns the remainder (369 megawatts).

In its rebuttal testimony, the Company offered a rate mitigation proposal that would reduce Sherco 3 test-year costs by approximately $35 million. First, Xcel agreed not to seek recovery of $4.4 million in variable O&M costs, including chemical costs, for the test year. Second, the Company proposed to defer Sherco 3's 2012 and 2013 property tax and depreciation expenses, totaling $31.45 million, and to amortize them over the unit's 21-year remaining life starting in January 2014. This latter proposal would require that Sherco 3's remaining life be suspended and restarted when the unit is back in service. It would also require the Commission to authorize the creation of a regulatory asset to allow for the deferral and amortization.

The Sherco 3 repair costs are covered by insurance, and Xcel stated that it has not included any of those costs in the current test year. However, Xcel agreed to provide a full accounting of repair costs and insurance recovery in its next rate case to ensure that no repair costs reimbursed by insurance are recovered from ratepayers.

2. The Department, the OAG, and Energy CENTS Coalition

The Department recommended that all direct costs for Sherco 3 be removed from the 2013 test year, arguing that it would be unfair for ratepayers to continue to bear the costs of a facility that has been out of service for nearly two years. The Department agreed to Xcel's proposal to defer the 2013 depreciation expense but recommended disallowing all other test-year expenses. The Department stated that its recommendation would result in a $36.6-million reduction in Xcel's test-year revenue requirement, not including the chemical costs.

The Department recommended that the Commission accept Xcel's 21-year remaining life estimate as a placeholder but suggested that the Company have an engineer confirm this estimate in view of the significant upgrades and restoration work done since Sherco 3's failure. Finally, the Department agreed with the Company's proposal to provide insurance information in the next rate case.

The OAG and Energy CENTS supported the Department's position.

3. The ICI Group

The ICI Group recommended that the fixed costs associated with Sherco 3 be removed from the 2013 test year. It argued that the unit is not "used and useful" because it has been out of service since 2011, with no guarantee that it will return to service in 2013. The ICI Group pointed out that Sherco 3 lost its capacity accreditation from the Midcontinent Independent System Operator (MISO) and that Xcel has been forced to buy higher-cost replacement energy on the MISO market as a result of the outage. The ICI Group concluded that it would not be just and reasonable for ratepayers to bear the costs of Sherco 3.

4. The Chamber

The Chamber objected to including Sherco 3 in rate base, arguing that the unit is not currently used and useful and that Xcel's projected in-service date is unreliable. The Chamber proposed that Sherco 3 be removed from rate base and remain out of rate base until it is back in service and fully accredited by MISO. According to the Chamber, this proposal would result in a $20.7 million adjustment to Xcel's revenue requirement.

The Chamber agreed with Xcel that 2013 depreciation and property taxes should be deferred, but it recommended that the Company refund 2012 depreciation and property taxes to the ratepayers, and that all of these items be deferred and recovered in the future as set out by Xcel. According to the Chamber, this would result in a $31.45 million adjustment.

Finally, the Chamber proposed removing legal costs, administrative costs, employee and overhead costs, and chemical costs from the 2013 test year. The Chamber noted that Xcel has agreed to a $4.4 million O&M adjustment but that it is unclear if this amount is correct.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Sherco 3 will be used and useful during the 2013 test year. The ALJ examined a Connecticut case with comparable facts and found the Connecticut commission's approach to the used-and-useful question helpful. In that case, three nuclear generators produced power for several years before going offline for extended outages. The key factor in the Connecticut commission's analysis was the degree of certainty that the units would resume service during the test year. The ALJ reasoned that, because Sherco 3 has been in rate base for a number of years and there is reasonable certainty that the plant will resume service during the 2013 test year, the unit should be considered used and useful.[16]

However, because Sherco 3 has not been operating for most of 2013, the ALJ recommended removing avoidable O&M costs from the test year,[17] deferring all other 2013 direct costs, and amortizing them beginning in 2014.[18] The ALJ's recommendation is consistent with Xcel's rebuttal proposal, except that the ALJ recommended disallowing 2012 depreciation and property taxes because they are outside the test year. The ALJ calculated that this recommendation would result in a reduction of approximately $39.9 million from the 2013 test-year revenue requirement.[19]

D. Commission Action

The Commission concurs with most of the Administrative Law Judge's findings and conclusions on this issue but respectfully declines to adopt the recommendations set forth in paragraphs 134–136. While the Commission agrees with the ALJ that the task at hand is to equitably balance the interests of the ratepayers and the shareholders regarding Sherco 3's extended hiatus, the Commission reaches a different conclusion as to where this balance should be struck.

On the one hand, Xcel's investment in Sherco 3 provided many years of service before the outage, and the unit is expected to operate for many more years once it returns to service. On the other hand, Sherco 3 has been unavailable to ratepayers for nearly 22 months. Even accepting Xcel's prediction of a September 2013 in-service date, the unit will have been offline for most of the test year. And, although past costs related to Sherco 3 are not directly relevant to the reasonableness of

[16] ALJ Report, ¶ 121.

[17] Id. at ¶ 129.

[18] Id. at ¶¶ 133–34.

[19] Id. at ¶ 136.

the test-year costs, ratepayers' payment of substantial O&M and replacement-power costs during the outage underscores the need for caution in evaluating the Company's current request.

The Commission concludes that the most equitable resolution is to remove all direct Sherco 3 costs, except property taxes, from the test year. Property taxes are an unavoidable cost that Xcel incurs regardless of whether the unit is operating, and the Company should be able to recover this expense while it works to repair the unit and restore it to service. Additionally, the Commission will allow Xcel to defer the unit's 2013 depreciation expense.

Allowing the depreciation expense recognizes the benefit that Xcel's investment has provided to ratepayers in the past and will provide again once Sherco 3 is up and running. And deferring the expense appropriately relieves ratepayers from bearing the costs of a generating unit during a period when they derived no benefit from it, and in fact were bearing other costs to replace the power it had been expected to generate. Deferral recognizes that, although the unit was not used and useful during the 2013 test year, it remains a valuable asset and an integral part of the Company's generating fleet.

The Commission accepts Xcel's proposed 21-year remaining life as a placeholder. However, because of the significant repair work done to Sherco 3, this value needs to be confirmed. The Commission will therefore require the Company to have an engineer evaluate the unit and provide this analysis in its next rate case. Finally, the Commission also accepts Xcel's offer to provide a full accounting of repair costs and insurance recovery in its next rate case to ensure that no repair costs reimbursed by insurance are recovered from ratepayers.

The Commission cannot conclude at this time who should bear the significant costs the Company has incurred for replacement power. That issue may be examined when the Company files its petition for approval of its fuel cost adjustment.

VII. Nobles Wind Farm Costs

A. Introduction

Under Minnesota's Renewable Energy Standard (RES), Xcel is required to supply an increasing percentage of its Minnesota retail customers' demand for electricity from renewable energy.[20] To comply with its RES obligation, Xcel maintains a renewable energy portfolio that includes both Company-owned projects and contracts with independent power producers.

In June 2009, the Commission approved Xcel's investment in Nobles Wind Project (Nobles), a 201-megawatt wind farm in Nobles County.[21] Xcel selected Nobles from among 30 bids submitted in response to a request for proposals (RFP) for wind projects to be constructed by other companies and then transferred to Xcel to own and operate. The Commission did not address rate recovery in that proceeding.

[20] Minn. Stat. § 216B.1691, subd. 2a(b).

[21] *In the Matter of the Petition of Northern States Power Company for Approval of Investments in Two Wind Power Projects,* Docket No. E-002/M-08-1437, Order Approving Investments and Expenditures (June 10, 2009).

Xcel first requested recovery of Nobles costs in its September 2009 RES Rider filing. The project costs exceeded Xcel's estimate in the previous docket. The Commission denied recovery of the additional costs, limiting recovery through the RES Rider to Xcel's original estimate ("RES Rider Order"). However, the Commission also stated that it would allow Xcel to seek recovery of the additional costs "at the time of its next rate case, upon a showing that it is reasonable to require ratepayers to pay for any such additional costs."[22]

In its next rate case, filed November 2010, Xcel sought recovery of the additional Nobles costs. The Department and the Chamber opposed recovery of these costs. The Commission did not decide the issue because the parties reached a settlement.[23]

B. Positions of the Parties

1. Xcel

Xcel renewed its request to recover additional Nobles costs in this rate case. The Company seeks approximately $5.6 million in additional capital costs, including overhead costs, higher-than-expected lump-sum payments to landowners, and contingency costs.

Xcel maintained that all costs incurred to complete Nobles were reasonable, prudent, and necessary to the provision of service. It pointed out that these costs were not project-specific cost overruns but system costs that would have been incurred under any build–transfer scenario. Finally, the Company noted that neither the RFP process nor the Commission's order approving the Nobles investment set a cap on recoverable costs and asserted that the parties understood that additional costs were a possibility.

In its rebuttal testimony, Xcel proposed treating the additional capital costs like an "investment in cancelled plant," whereby the Company would recover a return of but not on its investment over a reasonable period of time, such as ten years.

2. The Department and the Chamber

The Department argued that, absent some extraordinary justification, the reasonable cost of the Nobles project should be the amount of the competitive bid. The Department asserted that Xcel had not shown the reasonableness of the cost overruns. The Department specifically challenged the increased landowner payments, noting that, in the last rate case, two Xcel witnesses had provided conflicting explanations for this increase.

The Chamber supported the Department's position.

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[22] *In the Matter of the Petition of Northern States Power Company for Approval of the 2010 Renewable Energy Standard Cost Recovery Rider and 2009 Renewable Energy Standard Tracker Report*, Docket No. E-002/M-09-1083, Order Approving 2010 RES Rider and 2009 RES Tracker Report (April 22, 2010).

[23] 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-10-971.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Xcel's request for recovery of additional costs was time-barred by language in the Commission's RES Rider Order allowing the Company to seek recovery of the costs "at the time of its next rate case." The ALJ noted that Xcel sought recovery of the additional Nobles costs in the 2010 rate case, "its next rate case." However, because the parties settled that case, Xcel did not obtain the Commission's authorization to recover the costs.[24]

Finally, recognizing that the Commission might interpret the RES Rider Order differently, the ALJ found that the additional costs were reasonable and alternatively recommended that the Commission adopt Xcel's rebuttal position and allow recovery of the costs over ten years with no return on investment.[25]

D. Commission Action

The Commission concurs with most of the Administrative Law Judge's findings and conclusions on this issue. However, the Commission respectfully disagrees with the ALJ's conclusion that Xcel's request is time-barred by the Commission's RES Rider Order. The Commission therefore adopts the ALJ's alternative recommendation with a modification to amortize the costs over the wind farm's remaining life rather than a ten-year period.

The purpose of the RES Rider Order was to limit the costs Xcel could recover through the RES Rider to its original estimate but allow the Company an opportunity to justify recovering the additional costs in a general rate case. The language "at the time of its next rate case" reflects not an intent to limit the time within which Xcel is allowed to seek recovery but rather an expectation that the Company would want to do so at the next available opportunity. Further, the Company *did* seek recovery in its next rate case—the procedural posture of that case, however, and the manner of its disposition resulted in no clear adjudication of the issue. The Commission therefore concludes that Xcel's request to recover the additional Nobles costs is not time-barred.

Having concluded that Xcel's request is timely, the Commission concurs with the ALJ that the additional Nobles costs are reasonable and will allow the Company to recover these costs. However, recognizing that Xcel failed to disclose the costs when the Commission originally approved the Nobles project, the Commission will accept Xcel's proposal to allow a return of, but not on, the $5.6 million jurisdictional cost. The Commission will direct the Company to amortize the cost over the wind farm's remaining life to mitigate the impact on rates.

VIII. Depreciation Reserve Surplus

A. Introduction

Depreciation refers to the loss of an asset's service value due to consumption or prospective retirement, other than losses that can be restored through routine maintenance or paid for by insurance.[26] Assets may depreciate due to wear and tear, decay, action of the elements,

[24] ALJ's Report, ¶¶ 444, 446.

[25] *Id.* at ¶¶ 447–51.

[26] Minn. R. 7825.0500, subp. 6.

inadequacy, obsolescence, changes in the art, and changes in demand and requirements of public authorities, among other causes.[27]

Depreciation accounting permits a utility to recover, over the span of a tangible asset's useful life, the cost of the assets plus the cost of decommissioning the asset.[28] For each type of utility asset, a utility recovers depreciation expense from ratepayers and records them into a depreciation reserve. To promote appropriate depreciation practices, each energy utility must obtain Commission certification of the utility's depreciation rates.[29] A utility must use straight-line depreciation—depreciating an equal amount of an asset's cost plus decommissioning costs in each year of the asset's probable service life—unless the Commission authorizes an exception.[30]

The appropriate depreciation reserve was at issue in the Company's last rate case, Docket No. 10-971. As part of the settlement in that case, the Company agreed to reduce its depreciation reserve and to complete the review of its depreciation in its 2012 Five-Year Depreciation Study.[31]

In this case, XLI and the Chamber argued that Xcel has over-recovered depreciation costs from its ratepayers, and proposed that Xcel amortize these funds over a five-year period; Xcel and the Department opposed these recommendations.

B. Positions of the Parties

Citing Xcel's recent depreciation filings,[32] XLI argued that Xcel over-collected depreciation funds from its current ratepayers. In other words, XLI alleged that the amount of money Xcel has accrued for the depreciation of these assets exceeds its theoretical reserves—that is, the amount Xcel should have accrued based on current estimates of the remaining lives of the facilities and the net costs of decommissioning them. According to XLI, Xcel has over-accrued from Minnesota ratepayers $265 million for transmission, distribution, and general plant, and $219 million for production plant—primarily related to Xcel's nuclear generating units at Monticello and Prairie Island.

In remedy, XLI proposed that Xcel repay these excess funds to its ratepayers over the next five years. In effect, this practice would help offset rate increases established over that period. In

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[27] *Id.*

[28] *Id.* at subp. 7.

[29] Minn. R. 7825.0700, subp. 1.

[30] Minn. R. 7825.0500, subp. 14; 7825.0800.

[31] *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-10-071, Findings of Fact, Conclusions, and Order (May 14, 2012) at 13.

[32] See *In the Matter of Xcel Energy - Electric & Gas 2012 Annual Review of Remaining Lives*, Docket No. E,G-002/D-12-151 (regarding production plant) and *In the Matter of Northern States Power Company d/b/a Xcel Energy's Five-Year Transmission, Distribution and General Depreciation Study*, Docket No. E,G-002/D-12-858 (regarding transmission, distribution, and general plant).

support of its proposal, XLI cited a ratemaking treatise and decisions from other states.[33] The Chamber joined XLI in recommending that the Commission amortize the transmission, distribution, and general plant surplus over five years.

Xcel and the Department opposed XLI's proposals.

Regarding its production plant, Xcel denied that it has excess theoretical reserves. According to Xcel, XLI generated its initial estimate of Xcel's theoretical reserves by assuming that all its assets would have the same operating life as the underlying generators, without acknowledging that parts of the plants would retire sooner. And when XLI adjusted its calculation based on interim retirements from 2007 to 2011, Xcel argued that these years do not provide a representative sample of interim retirements prospectively. Rather, Xcel argued that its depreciation studies demonstrate that Xcel has an appropriate amount of depreciation reserves for production plant, given the anticipated service lives of all the assets involved.

Regarding its transmission, generation, and general plant, Xcel acknowledged that it has accrued surplus reserves. But rather than amortizing this amount over five years, Xcel and the Department recommended amortizing the surplus over 33 years, the average remaining life of the assets. Xcel and the Department argued that this practice would be consistent with the remaining life method of depreciation and the Commission's rule favoring straight-line depreciation.

Moreover, Xcel and the Department questioned the fairness of turning funds that had been accrued from Xcel's past customers into a windfall benefiting customers over the next five years. And they questioned the wisdom of adopting a policy that would depress net depreciation expense over five years, only to increase that expense thereafter. Indeed, Xcel and the Department argued, it is foreseeable that Xcel's depreciation expense will soon increase due to the increased investments in production plant (especially the Monticello and Prairie Island nuclear generating units) and transmission plant (especially the CapX 2020 transmission lines).

C. Recommendation of the Administrative Law Judge

The ALJ generally concurred with the Department and Xcel, and adopted their recommendations.

Regarding production plant, the ALJ concluded that Xcel had established that interim plant retirements would largely consume the apparent depreciation reserve surplus. Moreover, the ALJ found it prudent to avoid accelerating the depletion of the production plant depreciation reserves when Xcel has just made large investments in its nuclear generators, increasing the amount of production plant it has to depreciate.

Regarding transmission, distribution, and general plant, the ALJ recommended amortizing the reserve surplus over the average remaining lives of the assets. She concluded that five years is simply too short a period to amortize the reserve surplus, benefitting near-term ratepayers at the expense of ratepayers six or more years into the future. But the ALJ acknowledged that the period

[33] Citing the ratemaking manual of the National Association of Regulatory Utility Commissioners (NARUC); Florida Public Service Commission decisions (regarding Florida Power & Light Company and Progress Energy Florida); Georgia Public Service Commission decision (regarding Georgia Power Company).

over which the surplus is amortized is a matter of judgment, and that various periods fall within the range of reasonableness. She suggested that a 15-year amortization period would be reasonable and could provide ratepayer benefits in the near term as Xcel is pursuing especially large rate increases.

Finally, the ALJ recommended that the Commission direct Xcel to work with the parties to explore other reasonable approaches, and to reconsider this matter in Xcel's next rate case.

XLI and the Chamber took exception to the ALJ's recommendations, restating their claims above. Citing the principle that depreciation is designed to recover the cost of existing plant, XLI argued that it is inappropriate for the ALJ to consider Xcel's new and impending plant additions in addressing its current depreciation reserve surpluses. And XLI argued that her finding that a five-year amortization period is "too short" was unsupported by any record or analysis.

D. Commission Action

1. Transmission, Distribution, and General Plant

Regarding Xcel's transmission, distribution, and general plant, no party disputes that Xcel has accrued a depreciation surplus or that the surplus should be amortized. The parties merely disagree about the period over which to amortize it. And, as the ALJ observed, the Commission may pick from a range of reasonable periods.

A variety of policy considerations influence the Commission's decision, including rate shock mitigation, rate stability, and intergenerational equity.

- *Rate shock mitigation:* Given the size of Xcel's proposed rate increase, a choice to amortize funds sooner will help offset that increase.

- *Rate stability:* As Xcel and the Department observe, the choice to accelerate the amortization necessarily benefits near-term customers at the expense of later customers. A longer amortization period may help mitigate future rate shock. And while the Commission does not set depreciation rates for the purposes of recovering the cost of future plant, the Commission is not precluded from considering all relevant factors in evaluating the reasonableness of an amortization schedule.

- *Intergenerational equity*: In general, depreciation policies are designed to cause the customers who benefit from a plant to bear their proportionate share of the plant's cost – no more, no less. This is the purpose of the Commission's rule favoring straight-line depreciation. Because Xcel's past customers have borne a disproportionate share of certain plant costs, an appropriate remedy would target benefits to the customers who bore the burden. Some of Xcel's past ratepayers remain current ratepayers, but ever more will move away or die over time. If the goal is to benefit past ratepayers, therefore, Xcel could better achieve that end by targeting benefits to current ratepayers rather than later ones.

Contrary to the arguments of Xcel and the Department, amortizing the surplus over the remaining life of the transmission, distribution, and general plant in a straight-line fashion would spread the benefit of the surplus away from the customers that bore the disproportionate cost—frustrating the very policy that straight-line depreciation is intended to promote.

Ultimately the ALJ concluded that a five-year amortization period was too short. The ALJ then recommended amortizing the reserve surplus over the average service life of the plant—but acknowledging that countervailing considerations might justify a shorter period, she also suggested a 15-year period.

The Commission concurs that a five-year amortization period is too short, giving insufficient consideration to rate stability. But the Commission also finds that amortizing the surplus over the life of the plant would give insufficient consideration to issues of rate shock mitigation and intergenerational equity. While the ALJ suggested a 15-year amortization period, the Commission favors a period of roughly half that duration. Balancing the competing considerations, the Commission will direct Xcel to amortize the depreciation reserve surplus for its transmission, distribution, and general plant accounts over eight years.

2. Production Plant

Finally, the Commission concurs in the ALJ's recommendation regarding Xcel's production plant depreciation reserves, especially regarding Xcel's nuclear generating units. The preponderance of the evidence indicates that these reserves appropriately reflect the cost of production plant retirements, including interim retirements, as explained by Xcel and the Department. Because the Commission finds insufficient reason to conclude that this reserve has a surplus, the Commission will decline XLI's proposal for amortizing the surplus.

However, this decision is not intended to preclude continued monitoring and analysis. The Commission will direct the parties to explore this matter more fully in Xcel's next rate case.

IX. Sales Forecast

A. Introduction and Background

The Commission requires a reasonable test-year sales forecast as the foundation for determining just and reasonable rates. Test-year sales volumes are important factors in calculating a utility's revenue requirement, rate design, and conservation cost recovery charge because sales levels affect both revenues and expenses. Lower sales levels will normally result in higher rates since costs are spread over fewer units.

The Department expressed concern that Xcel's forecast underestimates test-year sales. It challenged Xcel's methodology based on four claims:

- Xcel underestimated its total number of customers;
- Xcel overestimated energy prices;
- Xcel improperly used a binary factor to account for the loss of two large industrial customers; and
- Xcel overadjusted for the effect of demand-side management (DSM).

The Department recommended modifications to address each of these issues. The ALJ accepted the Department's modifications with respect to the first three issues but found that a DSM adjustment was proper.

The Commission concurs in the ALJ's analysis of customer count, energy prices, and sales to large commercial and industrial customers and adopts the ALJ's findings and conclusions on those issues. However, the Commission respectfully disagrees with the ALJ's resolution of the DSM-adjustment issue, as discussed below.

B. Positions of the Parties

1. Xcel

Demand-side management, or DSM, refers to measures taken by a utility to reduce customer demand for energy, such as promoting the use of efficient appliances. Xcel argued that, without an adjustment to account for a recent upward trend in energy savings from DSM, its forecast will overestimate energy sales. Xcel calculated a DSM adjustment by taking the difference between the Company's expected DSM savings in 2013 and a five-year historical average (2007–2011).

2. The Department

The Department argued that a DSM adjustment would underestimate 2013 sales, harming ratepayers through the resulting higher rates. The Department maintained that a DSM adjustment is unnecessary because the past sales data on which Xcel's projections are based already reflect historical DSM levels. No additional adjustment is needed since Xcel expects its DSM savings to level off in the future.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel's proposed adjustment risks double-counting some of the DSM savings already reflected in historical sales data. The ALJ recommended using a four-year average of DSM savings instead of Xcel's five-year average as a baseline for calculating a DSM adjustment.

The ALJ also recommended several requirements for Xcel's next rate-case filing to aid the Department's analysis of the sales forecast.

D. Commission Action

The Commission concurs with the Department that Xcel has not shown the reasonableness of a DSM adjustment in this case. A DSM adjustment would underestimate test-year sales for several reasons. First, historical DSM efforts are already reflected in the sales data used in the forecast. Second, data provided by the Department show that Xcel's yearly DSM savings are leveling off, rather than increasing. Finally, Xcel's sales forecast with the DSM adjustment is consistently lower than actual data for five out of the last six months of 2012. For these reasons, the Commission will adopt ALJ Finding 252, revised as follows:

> 252. As shown by the Department, the Company has not proven the reasonableness of a DSM adjustment in this proceeding. The inclusion of a DSM adjustment will under-estimate test-year sales and should not be applied to the sales forecast in this proceeding. ~~the best method of accounting for DSM related savings beyond the first year of a device's implementation, while avoiding an overestimation of the impact of these savings, is to use a four~~

~~year average to calculate embedded DSM. This approach would increase the sales forecast by 51.161 MWh or $3.0 million in revenue above the forecast resulting from the five-year average advocated by the Company.~~

Overall, the Commission finds that the Department's recommendations result in a sales forecast that is reasonable, well designed, and appropriate for ratemaking in this case. The Department's recommendations increase the test-year retail revenue by $26,163,000.

Finally, the Commission concurs with the ALJ's recommendations for improving the transparency of Xcel's sales forecast. The Commission will require Xcel to include the following items in its next rate case:

1. Forecasting data at least 30 days prior to the initial rate case filing;
2. A comparison to the forecast information in this docket and the Baseload Diversification Study filed on or around July 1, 2013;
3. Large industrial customer account data in a format that allows interested parties to readily access historical data for all customers;
4. A spreadsheet, with all links intact, identifying any data inconsistencies with the Company's raw weather data and any modifications made to the raw weather data;
5. A detailed step-by-step explanation as to how test year revenue was calculated and what commands should be changed if a party wishes to adjust test year sales, adjust customer counts or calculate revenue;
6. A detailed description of the changes the Company has made to simplify its test year revenue calculation so that persons outside of the Company may verify the accuracy of the calculation; and
7. A report on the meetings Company representatives have had, prior to filing, with interested parties to explain its revenue calculation process and to cooperatively discuss methods for streamlining the revenue calculation.

X. Residential and Small General Service Customer Charges

A. Introduction

The monthly customer charge is a fixed monthly charge assessed without regard to usage levels. It is designed to help recover fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing

Xcel's current monthly customer charges are $7.11 for overhead residential customers, $9.11 for underground customers, and $8.61 for small general service customers. The average customer-related cost, according to the Company's revised Class Cost of Service Study (CCOSS), is $17.35 per month for a residential customer.

B. Positions of the Parties

1. Xcel

Xcel proposed to increase the monthly customer charges for overhead residential customers to $10.00, for underground customers and small general service customers to $12.00 to move these costs closer to the average cost of service. Xcel argued that its current overhead and underground customer charges are 59% and 47% below cost, respectively, while its proposed increase would result in weighted average customer charges that are only 62% of cost.

Xcel asserted that its proposals represent a moderate and reasonable movement towards cost, and help to balance the cost of service with other rate design objectives. The Company also argued that the proposed increase in customer charges poses little risk of interfering with conservation incentives because the increase removes only 0.5 cents per kWh in customer costs from the energy charge.

2. The Department

The Department agreed that an increase in the residential customer charge is reasonable, but argued that Xcel's recommendation imposes too high a charge. The Department asserted that its recommendations to increase the monthly customer charge for overhead residential customers from $7.11 to $8.50 per month, and for underground residential customers from $9.11 to $10.50 per month, are reasonable and consistent with the customer charges the Commission has approved for Minnesota utilities in recent rate cases.

The Department argued that its recommendation helps to balance the increase in the customer charge with the impact of intra-class subsidies. The Department asserted that if customer charges do not recover the full cost of connecting and keeping a customer on the electric system, such costs are recovered through the energy charge. The agency expressed concern that customers with higher usage levels (some of whom are low income) may be subsidizing the customer costs of lower usage customers with average or high incomes. The Department noted, however, that the only data available in this rate case that links customer usage with customer income is for customers receiving Low Income Home Energy Assistance Program (LIHEAP) assistance.

3. Suburban Rate Authority

The SRA recommended a more limited increase in the customer charge for residential customers than Xcel and the Department. The SRA recommended an increase from $7.11 to $8.25 for overhead customers, and from $9.11 to $10.50 for underground customers. The SRA argued that these increases, which represent about a 16% increase over current basic charges, are moderate and reasonable, and help to promote conservation by recovering a portion of the fixed charges through usage-based rates. In its exceptions to the ALJ's recommendation, the SRA argued against increasing the customer charge for overhead service customers by a higher percentage than underground service.

4. OAG

The OAG opposed the Company's proposed increase in the customer charge, and recommended that the Commission approve no increase in the monthly residential and small commercial customer charges. The OAG argued that Xcel's request is unprecedented in terms of its size and

would result in rate shock and hardship for customers on low or fixed incomes. The OAG pointed out that it has been less than a year since the Company increased its residential customer charges by $1.00 (or about 15%).

In exceptions to the ALJ's recommendation, the OAG asserted that to accept the Department's proposed customer charges results in a 20% increase in customer charges for residential overhead customers and a 15% increase for residential underground customers, after the 15% increase in the last rate case. The OAG argued that such increases would violate the ratemaking principles of continuity with prior cases and ease of customer understanding.

5. Energy CENTS Coalition

Energy CENTS also opposed any increase in the customer charges, arguing that high customer service charges disproportionately harm the lowest usage and low-income customers—the groups least able to absorb high customer charges.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission raise the residential customer charge to $8.50 per month for overhead customers and $10.50 per month for underground customers, as recommended by the Department.

D. Commission Action

Having reviewed the record, including the oral and written arguments of all parties and members of the public, the Commission finds that it cannot adopt the recommendation of the Administrative Law Judge with respect to the increases in the Company's customer charges. The residential class only recently absorbed an approximately 15% increase in the customer charge in the Company's last rate case, decided little more than a year ago.[34]

While the ALJ's recommendation is more moderate than that proposed by the Company, the Commission will not adopt the increase recommended by the ALJ. The Commission finds that such an increase, coming on the heels of the prior increase, is simply too high. And, while the ALJ's recommendation might move the customer charge closer to average cost, the Commission must also avoid any increase that could result in rate shock.

Further, customer charges do not vary with usage, and therefore no amount of conservation can reduce these costs. A significant increase in the customer charge can act as a disincentive to conservation, working at cross-purposes with the statutory directive that "[t]o the maximum reasonable extent, the commission shall set rates to encourage energy conservation."[35] In fact, many members of the public commented that the rate increases proposed in this case would discourage conservation.

For all these reasons, the Commission will decline to authorize another increase in the customer charges of the size recommended by the ALJ at this time, without deciding what the Commission will do in the future.

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[34] Docket No. E-002/GR-10-971.

[35] Minn. Stat. § 216B.03.

Accordingly, the Commission will impose the following level of customer charges in this case:

Residential Overhead – Standard	$ 8.00
Residential Overhead – Heating	$10.00
Residential Underground – Standard	$10.00
Residential Underground – Heating	$12.00
Small General Service	$10.00

XI. Additional Energy Assistance Funding

A. Introduction

Minn. Stat. § 216B.16, subd. 14, requires certain public utilities to fund an affordability program for low-income customers, and requires the Commission to establish by order how costs for those programs are recovered. The Company implements its affordability program with two components,[36] and the Commission ordered that the Company recover program costs through a single monthly, fixed per-meter surcharge.[37]

According to the Company:

> The Program's discount component ("Discount Program") provides a 50 percent discount on energy and fuel charges up to the first 400 kWh of consumption each month to low income customers qualifying as seniors or disabled.
>
> The Program's affordability component ("Power On") provides bill discounts to qualified customers in return for the customer's commitment to a payment plan for the account balance. Power On is available to certified, low income customers with amounts owing for electric service that exceed three percent of their household income.[38]

However, the Energy CENTS Coalition testified that one of the two programs, PowerON,[39] has been closed to new participants since September 2012 to avoid overspending available energy assistance funds.

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[36] *In the Matter of the Petition of Xcel Energy for Approval of its Electric Low Income Program Meter Surcharge*, Docket No. E-002/M-10-854, Petition to Approve Low Income Energy Discount Rider, pages 3–4 (July 30, 2010).

[37] Docket No. E-002/M-10-854, Order Approving Cost Allocation (April 5, 2012).

[38] Docket No. E-002/M-10-854, Petition to Approve Low Income Energy Discount Rider, 4 (July 30, 2010).

[39] Filings in this proceeding have referred to the program as "POWER On," and "Power ON." Previous Company filings have referred to "Power On." Petition to Approve Low Income Energy Discount Rider, Docket No. E-002/M-10-854, 4 (July 30, 2010). The Minnesota Office of Energy Security has commented on inconsistency in the program's name. Comments of the Minnesota Office of Energy Security, Docket No. E-002/M-10-854, n.3 (November 5, 2010). Previous Commission orders have generally used "PowerON." *See, e.g.*, Order Approving Increase in Cost Recovery for Electric Low Income Energy Program, Docket No. E-002/M-10-854 (January 28, 2011). For consistency, this order adopts that convention.

B. Positions of the Parties

The Energy CENTS Coalition argues that because a large number of eligible households are turned away from the Company's low-income energy assistance program for lack of funds, increased funding for the PowerON program is appropriate. It also argues that a dedicated source for PowerON funds would be appropriate to ensure stability for participants. The Energy CENTS Coalition proposed—and the Company and the Department support—increasing dedicated funding to the PowerON program by $3,200,000.

Energy CENTS initially proposed using the Company's residential late payment charges as the source of the increased funding. But the Company argued that using the late payment charges as the source of the funds would be an unstable funding source, and would require unnecessarily complicated tracking.

The Company counter-proposed that the amount of additional funding be based on Minnesota electric-jurisdictional residential late payment charges without actually using those charges as the source of the funds. The Energy CENTS Coalition revised its proposal in light of the Company's suggestion, and the Company and the Department supported the revised proposal.

The parties did not all agree on the source or rate treatment of the additional funds. The Chamber agreed with the increased funding proposal, but argued that the funding should be pro-rated in the test year, contending that $3,200,000 could not be spent in what remains of 2013. The Commercial Group agreed with the additional assistance program in principle, but argued in its post-hearing brief that Xcel should be required to pay half of the additional funds.

C. Recommendation of the Administrative Law Judge

The ALJ's findings and conclusions on this issue are addressed in paragraphs 491–501 of the report. The ALJ concluded that the revised Energy CENTS Coalition recommendation to increase funding to the PowerON program by $3,200,000 annually was reasonable, was consistent with state law, and should be adopted.[40]

D. Commission Action

The Commission adopts the ALJ's analysis, findings, and conclusions found in paragraphs 491 – 501, with the modifications detailed below.

The need for additional energy assistance funding does not appear to be controverted by any party, and is well supported in the record. As the ALJ noted, thousands of low-income households have been denied assistance through the PowerON program for lack of funds.[41] PowerON has not accepted new participants since September 2012.

The Commission agrees with the ALJ that an annual increase of $3,200,000 for assistance to low-income households is reasonable and appropriate. The additional funding will allow

[40] ALJ Report, ¶501.

[41] Id. at 301 n.566; Marshall Direct Testimony, 16 (February 28, 2013).

approximately 5,100 additional participants in the PowerON program, which, besides assisting low-income customers who may be at risk of disconnection, reduces the Company's collection costs by encouraging timely repayment of balances due to the Company.

The Commission concludes that the most appropriate source for the needed energy assistance funds is the mechanism that the Company already uses to collect energy assistance funds. The Commission determined in 2012 that a monthly, fixed per-meter surcharge, based on a ratio of the customer charge paid by each class, constitutes the most equitable method of funding the Company's energy assistance program. The Commission concludes that the surcharge remains equitable and appropriate. The surcharge provides a stable funding mechanism that reasonably matches program costs and benefits.

The Commission will therefore approve the $3,200,000-per-year budget increase for a separately funded PowerON program and require the Company to fund this program using the energy assistance surcharge methodology described in the Commission's April 5, 2012, order.[42] The Company will be required to segregate and separately track the additional $3,200,000 increase in funding from the other money it collects through the low-income affordability surcharge and to use this money only for the PowerON program. The Company will be responsible for any spending over the $3,200,000 per year budget for this part of the Company's PowerON program. Because the additional funding will be collected through a surcharge, it will not be included in base rates.

The increase should be implemented on January 1, 2014, or the date that the final rates in this rate case take effect.

XII. Interest Rate on Interim Rates Refund

A. Introduction

Minnesota Rules 7825.3300 provides that the Commission may suspend a utility's proposed rates while a rate case is pending but allow the utility to put suspended rates into effect subject to a refund once final rates are established. The rule requires that the portion of interim rates that exceeds the final rates must be refunded to customers "including interest at the average prime interest rate computed from the effective date of the proposed rates through the date of the refund or credit." The Commission suspended the Company's proposed rates in this proceeding on December 26, 2012.[43]

In this case, the interest rate required by the rule is 3.25%. Several parties argue that the Commission should vary the rule to require a higher interest rate.

The Commission varies its rules when it determines that

> 1. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;

[42] Docket No. E-002/M-10-854, Order Approving Cost Allocation (April 5, 2012).

[43] Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing (December 26, 2012).

2. granting the variance would not adversely affect the public interest; and
3. granting the variance would not conflict with standards imposed by law.[44]

B. Positions of the Parties

The Department, the Chamber, and the OAG recommend that the Commission conclude that the variance requirements have been met and that the Commission establish a higher rate of interest for interim rates than the rate ordinarily required by Minn. R. 7825.3300. The OAG recommends that the Commission establish the interest rate at the Company's rate of return established in this order.

The parties contend that in this case the prime interest rate is unreasonably low for the purpose of calculating the appropriate amount of interest to return to ratepayers. The Department and the OAG assert that the historically low rate gives the Company incentive to overstate its request and effectively use ratepayers as an inexpensive source of funds. They also contend that the frequency and magnitude of recent Company interim rate refunds have cumulatively imposed a burden on ratepayers, justifying a variance.

The Chamber further argues that it is inequitable for the Company to charge its customers a higher rate when the Company effectively extends ratepayers credit through carrying charges, or when remedying under-recovery in rider proceedings. The parties contend that ratepayers will therefore suffer an excessive burden if the rule is not varied.

The Company denies that it has an incentive to overstate its revenue request, and states that it treats interim rate revenues as a short-term resource because it is usually available for one year or less. The Company contends that the current prime rate is significantly higher than its short-term borrowing rate.

C. Recommendation of the Administrative Law Judge

The ALJ's findings and conclusions on this issue are addressed in paragraphs 835 – 850 of the ALJ's report. The ALJ concluded that varying the rule would not conflict with standards imposed by law, nor would it adversely affect the public interest. However, she concluded that the first element of the variance rule—that enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule—had not been met.

The ALJ, upon determining that only two of the three elements of the rule governing Commission rule variances had been established, therefore recommended that the Commission not vary the rule unless it determined that enforcement of rule 7825.3300 would impose an excessive burden on those it affects.

[44] Minn. R. 7829.3200.

D. Commission Action

The Commission adopts the ALJ's analysis, findings, and conclusions found in paragraphs 835 – 850, except to the extent they are inconsistent with or are expressly modified in the following discussion. The Commission agrees with the ALJ's reasoning and conclusions concerning whether the record satisfies the second and third elements of Minn. R. 7829.3200, but finds that all three prongs of Minn. R. 7829.3200 have been met and therefore will vary rule 7825.3300.

1. The Elements of Minn. R. 7829.3200 Have Been Met

The Commission agrees with the Department, the OAG, and the Chamber that ratepayers are affected by the interim refund rule, and that enforcement of the rule without a variance would impose an excessive burden upon them. The Company's final rates established by this order are substantially lower than the company's interim rates. Ratepayers have been paying higher rates premised on the Company's initial request for a 10.7% increase in rates, effectively lending the Company the difference between interim rates and final rates. Further, the magnitude and frequency of the Company's interim rate over-collection over successive years has a cumulative effect on ratepayers.

The utility has much greater control than ratepayers over whether, when, and how much ratepayers must borrow from or lend to the utility. The Company acknowledges that the interest required by the rule is paid in recognition that the Company had use of funds while interim rates were in effect. The ALJ in Finding 846 identified one circumstance where, when the positions are reversed, the Company imposes a substantially higher rate of interest on ratepayers; the Commission commonly sets carrying charges at the Company's authorized rate of return. Additionally, the prime rate is at historically low levels to accommodate a federal monetary policy that was not anticipated when the interim rate refund rule was adopted.

Not only does it serve the public interest to recognize this disparity in borrowing costs, but in this case, the rule's low interest rate relative to the Company's authorized rate of return constitutes an excessive burden on ratepayers as captive lenders. Low-income households may particularly suffer hardship when interim rates are over-recovered, and ratepayers generally cannot replace the money the Company borrows at near the prime rate. To impose this hardship in light of the magnitude of this and other recent interim rate over-collections would be an excessive burden. The Commission finds that the first element of Rule 7829.3200 is met.

The second element—no adverse effect on the public interest—is met because it serves the public interest to promote greater equity between utility and ratepayer borrowing costs and to further discourage overstatement of interim rate requests.

The Commission also finds that the third element of the variance rule—no conflict with any other legal standard—is met. The other applicable legal standard, Minn. Stat. § 216B.16, subd. 3, states that the refund of interim rates shall be at the rate of interest determined by the Commission.

2. The Appropriate Interim Rate Refund Interest Rate is 7.45%

Having found that the elements of Minn. R. 7829.3200 are satisfied—and having determined that the interest rate required by rule is so low as to impose an excessive burden on ratepayers—the

Commission must vary 7825.3300. Recognizing that there may be a range of reasonable interest rates to impose, the Commission will require Xcel to refund the interim rate over-collection using the rate recognized in this case as the Company's overall cost of capital: 7.45%. The cost of capital is a weighted average of the Company's financing costs from all sources: short-term debt, long-term debt, and common equity.

The Commission concludes that this rate appropriately balances the interests of ratepayers, the utility, and the public. The utility's overall cost of capital represents the cost of alternative sources of utility funds, weighted for the utility's reliance on those sources. Returning borrowed interim rate funds to ratepayers at this rate most equitably compensates ratepayers for forgone opportunities had they not been compelled to lend money to the utility, without penalizing the Company relative to its average cost to obtain funds in the market. Requiring a refund with 7.45% interest will also more closely align the Company's interests with the public's interest that interim rates not repeatedly exceed final rates by large margins.

Consistent with the above analysis and conclusions, the ALJ's findings 846, 848, and 849 will therefore be modified as follows:

> 846. Because the Company seeks to impose a carrying charge on its customers for nuclear refueling outage costs that is equal to its rate-of-return, grossed up for taxes, the Administrative Law Judge concludes that the public interest would not be adversely affected if the Company were required to pay that same rate on interim rate refunds. Both rates are essentially payments for the use of money. The Commission may also note several other points wherein the Company charges a much higher return for under recovery or short-term funds from ratepayers, including under recovery in rider proceedings such as Renewable or Transmission rider and CIP Riders. The Company has failed to explain how the public interest is served by Company paying only 3.25 percent interest on the interim rate refund at the same time imposing a much higher rate on its customers as a carrying charge.
>
> 848. The Department demonstrated ~~None of the parties have shown~~ that the first prong is met in the circumstances identified in this proceeding. Department Witness Dale Lusti testified that "enforcement of the rule likely would impose an excessive burden on ratepayers." Mr. Lusti recommended that the Commission look at the facts in this case, including that Xcel has filed multiple cases, along with the difficulty Xcel had in supporting its case and the large difference in the overall rate of return and prime rate to determine whether the Commission concludes that ratepayers would be harmed by enforcement of the rule. ~~The Department re-characterized the first prong when arguing that the standard has been met. The Department asserted that "enforcement of the rule would not impose an excessive burden on ratepayers or the Company (because the Company is repaying to customers what the Company already charged to customers)." Similarly, the OAG asserted that "it is not an excessive burden to require NSP to refund~~

~~money to ratepayers that was over collected at the same rate it charges ratepayers on behalf of its shareholders." The MCC simply listed a number of facts that it maintains support a variance without addressing the prongs individually.~~

849. ~~Because the parties have not shown that the first prong is met, the Administrative Law Judge recommends that the Commission not grant the variance unless it determines, on its own, that "enforcement of the [average prime interest rate] rule would impose an excessive burden" on the Company or others affected by the rule.~~ The Department has shown that the enforcement of the rule likely would impose an excessive burden on ratepayers such that the first prong is met. The second and third prongs, regarding public interest and conflicting with legal standards were also met. The Commission varies Minn. R. 7825.3300 to require calculation of the interim rate refund at the rate of 7.45%.

XIII. Carrying Charge on Nuclear Refueling Outage Costs

A. Introduction

Since the conclusion of its 2008 rate case, the Company has been deferring and amortizing its nuclear refueling outage costs; the Commission approved this cost treatment to ensure greater accuracy in cost recovery, to match more closely the time these costs are incurred with the time they are recovered, and to avoid substantial fluctuations in these costs between rate cases. Parties challenged the Company's practice of including unamortized costs in rate base and charging or crediting ratepayers its rate of return on unamortized amounts.

B. Positions of the Parties

The Office of the Attorney General opposed a carrying charge as inappropriate but, if approved, the carrying charge approved should not exceed the Company's short-term cost of debt. (The OAG also opposed the deferral and amortization process itself, but did not file exceptions on that issue.)

The Company argued that applying a carrying charge was standard ratemaking practice and that the 18- to 24-month amortization period exceeded normal short-term-debt time frames.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended a lower carrying charge than the Company's rate of return, such as the short-term cost of debt or the prime interest rate.

D. Commission Action

The Commission concurs with the Company that the rate of return is the appropriate time-cost of money in this situation. The 18- to 24-month period over which these costs are normally amortized exceeds normal short-term-debt time frames, and the Company's 0.68% cost of short-term debt would not adequately compensate the Company or its ratepayers for this use of capital. Further, the

Company credits ratepayers at the rate of return when amortized amounts exceed actual costs, ensuring equitable treatment.

Finally, the Commission concurs with the OAG and the Company that deferred taxes prepaid by ratepayers must be included as a reduction to rate base.

XIV. Allocating Conservation Improvement Program (CIP) Costs

A. Introduction

Like all utilities, Xcel recovers its CIP costs in two ways – through a Conservation Cost Recovery Charge (CCRC) built into base rates and through a Conservation Cost Recovery Adjustment (CCRA), an automatic rate adjustment that trues up costs built into rates with actual costs. The Company calculates its CCRC using the percent-of-benefits method and its CCRA using the per-kWh method.

The percent-of-benefits method is more nuanced than the per-kWh method and more complex in its application. It is designed to reflect the cost allocations that would result from the supply-side investments the CIP expenditures permit it to forgo. The per-kWh method, on the other hand, simply divides the forecasted CIP tracker balance by forecasted energy sales.

In its January 2012 order reviewing Xcel's 2010 CIP tracker account, demand-side management financial incentive, and CIP adjustment, the Commission approved the Company's use of the percent-of-benefits method for its CCRC but directed the Company to include testimony on the issue in its next general rate case.[45] The Commission concurred with the Department that the administrative efficiencies that would result from all utilities using the same allocation method might outweigh the benefits of experimentation and marginal increases in precision.

B. Positions of the Parties

The Company argued that the percent-of-benefits allocation method more accurately allocates CIP costs by reflecting the cost allocations that would result from the supply-side investments the CIP expenditures permit it to forgo. The Company argued that, while the per-kWh method was simpler to administer and easier for customers to understand, those factors do not matter in the CCRC portion of the CIP adjustment, which is applied to base rates, not directly to customers' bills.

The Department recommended requiring the Company to use the per-kWh method for both recovery mechanisms, arguing that the Commission has stated a preference for moving toward uniformity in these calculations and has required other utilities to use the per-kWh method for all forms of CIP-cost recovery. The Department also stated that the per-kWh method simplifies regulatory oversight and has *de minimis* financial impacts; for Xcel, its use resulted in a $1,213 increase to the entire Commercial and Industrial Non-Demand Class and a $1,379 decrease for the entire Residential Class.

[45] *In the Matter of a Request by Xcel Energy for Approval of its 2010 CIP Tracker Account, DSM Financial Incentive, and CIP Adjustment,* Docket No. E-002/M-11-278, order issued January 11, 2012.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company had supported its use of the percent-of-benefits method in the CCRC as reasonable and recommended permitting the Company to continue to use it.

D. Commission Action

The Commission will require the Company to use the per-kWh method to calculate both the CCRC and the CCRA. As the Commission explained in its January 11 order:

> Over the past few years, the Commission has moved toward uniformity in its selection of the per-kWh allocation method for electric utilities. It did so for sound reasons, which remain valid. Of all the methods under consideration, the per-kWh method is the most straightforward, the easiest for customers to understand, and the most consistent with the statutory goal of reducing individual utilities' overall energy usage by a set percentage—normally 1.5%--on an annual basis. It appears to hold the greatest potential for reducing overall energy usage by sending the clearest price signal. This simplicity was and is its greatest strength.[46]

At this point, the administrative efficiency provided by industry-wide use of the more straightforward per-kWh allocation method outweighs any benefit from the marginal increase in precision provided by the percent-of-benefits allocation method.

XV. Technical Corrections and Clarifications

- ***ALJ Finding 663 on Stratification and Peak Demand Cost Allocation Methods –*** The Company filed noncontroversial, clarifying comments on ALJ Finding 663 and accompanying footnote 816, which the Commission adopts and includes in the ordering paragraphs.

- ***Allocating the Costs of the Gerdau Steel Discount –*** The Administrative Law Judge recommended approving the proposed Competitive Response Rider – which replaces the existing Competitive Market Rider – and allocating the costs of the new rider to all customer classes. The Company, the Department, and the Chamber pointed out that the costs of the old rider, whose only customer is Gerdau Steel, are currently allocated to the Commercial and Industrial Customer Class. The Commission clarifies that those costs should now be allocated to the general body of ratepayers.

- ***Pension Asset 2008 Market Loss –*** The Commission clarifies that its inclusion in qualified pension cost of the Company's 2008 market loss is limited to the facts of this case and is limited to this proceeding. Further evaluation and evidence of the Company's policy and practice pertaining to past and future pension policies, including surplus, must be provided in its next rate case. Any previously amortized 2008 Market Loss amounts that occurred prior to the filing of this rate case are not to be reflected in this or future test-year pension costs. And the Company shall not include a compensating return on the pension's unamortized asset loss balances.

[46] *Id*. at 5, footnote omitted.

- ***ALJ Finding 698 on Recommended Revenue Apportionment –*** The Company filed clarifying, noncontroversial comments on ALJ Finding 698, which the Commission adopts and includes in the ordering paragraphs.

XVI. Cost of Equity, Capital Structure, and Cost of Capital

The Company and the Department agreed on the Company's capital structure and on the cost of long- and short-term debt. The Administrative Law Judge concurred in their joint recommendation, as does the Commission.

The Company and the Department disagreed on the cost of common equity. As explained above, the Commission has set the cost of equity at the 9.83% recommended by the Department and the Administrative Law Judge.

The resulting overall capital structure and cost of capital are set forth below:

Component	Component Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	45.30	5.02	2.27
Short-Term Debt	02.14	0.68	0.01
Common Equity	52.56	9.83	5.17
Total	100.00%		7.45%

XVII. Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a total gross revenue deficiency of $102,797,000 for the 2013 test year as shown below:

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2013
($000's)

Line No.			
1	Average Rate Base	$	6,148,357
2	Rate of Return		7.45%
3	Required Operating Income	$	458,053
4	Operating Income before AFUDC	$	344,399
5	AFUDC	$	53,384
6	Total Operating Income	$	397,783
5	Income Deficiency	$	60,270
6	Gross Revenue Conversion Factor		1.705611
7	Gross Revenue Deficiency	$	102,797

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the 2013 test year is $6,148,357,000 as shown below:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2013
($000's)

Line No.			
	ELECTRIC PLANT IN SERVICE		
1	Production	$	7,070,952
2	Transmission		1,848,033
3	Distribution		2,943,837
4	General		416,005
5	Common		423,780
6	Total Plant In Service	$	12,702,607
	RESERVE FOR DEPRECIATION		
7	Production	$	3,942,582
8	Transmission		581,811
9	Distribution		1,184,850
10	General		157,696
11	Intangible		244,363
12	Total Reserve For Depreciation	$	6,111,302
	NET PLANT IN SERVICE		
13	Production	$	3,128,370
14	Transmission		1,266,222
15	Distribution		1,758,987
16	General		258,309
17	Intangible		179,417
18	Total Net Plant In Service	$	6,591,305
19	Construction Work in Progress	$	743,889
20	Accumulated Deferred Income Taxes	$	(1,389,939)
21	Cash Working Capital	$	(44,646)
	OTHER RATE BASE		
22	Materials & Supplies	$	110,516
23	Fuel Inventory		79,197
24	Non-Plant Assets & Liabilities		(30,254)
25	Prepayments		15,164
26	Nuclear Outage Amortization		70,396
27	Customer Advances		(1,940)
28	Customer Deposits		(2,926)
29	Other Working Capital		7,595
30	Total Other Rate Base	$	247,748
31	TOTAL AVERAGE RATE BASE	$	6,148,357

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the 2013 test year under present rates is $397,783,000 as shown below:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2013
($000's)

Line No.			
	UTILITY OPERATING REVENUES		
1	Retail Revenue	$	2,692,582
2	Interdepartmental		540
3	Other Operating Revenue		626,793
4	Total Operating Revenue	$	3,319,915
	EXPENSES		
	Operating Expenses		
5	Fuel & Purchased Energy	$	1,114,493
6	Power Production		653,277
7	Transmission		175,607
8	Distribution		96,728
9	Customer Accounting		49,264
10	Customer Service & Information		91,710
11	Sales, Econ Dvlp & Other		83
12	Administrative and General		179,112
13	Total Operating Expenses	$	2,360,274
14	Depreciation Expense	$	300,044
15	Amortization	$	18,793
	Taxes		
16	Property	$	152,298
17	Deferred Income Tax & ITC		156,773
18	Federal &State Income Tax		(39,873)
19	Payroll & Other		27,207
20	Total Taxes	$	296,405
21	TOTAL EXPENSES	$	2,975,516
22	AFUDC	$	53,384
23	TOTAL OPERATING INCOME	$	397,783

XVIII. Implementation and Compliance

The Commission will require the Company to make compliance filings 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 any 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.

ORDER

1. Xcel's Electric Utility is entitled to increase Minnesota jurisdictional revenues by $102,797,000 to produce jurisdictional total retail related revenue of $2,795,919,000 for the test year ending December 31, 2013.

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

3. The Company shall move from plant in-service to CWIP: 41.6% of the Monticello LCM/EPU costs for 2011 and 2012 additions added to the rate base in this case, 41.6% of 2013 May plant addition costs, and 100% of NRC fees, as well as the related depreciation reserve, deferred taxes, depreciation expense, AFUDC, and any other applicable costs. The Company may be allowed to recover those costs in future rate cases once the EPU is in service, subject to the plant being used and useful, and subject to a determination that the costs—including cost overruns—were prudent.

4. The Commission opens a new proceeding to investigate the prudence, reasonableness, and rate recoverability of the Monticello LCM/EPU project, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754.

5. The Commission directs the Executive Secretary, in consultation with the Department, to develop a proposal to be approved by the Commission for the conduct of an investigation into whether the Company's handling of the Monticello LCM/EPU project was prudent and whether the Company's request for recovery of Monticello LCM/EPU project cost overruns is reasonable. The proposal shall include the investigation scope, work plan, and retention of an expert under Minn. Stat. § 216B.62, subd. 8, to develop a report and recommendation to the Commission.

6. Xcel shall remove all direct costs for Sherco Unit 3, except for property taxes, from the 2013 test year.

7. The Commission approves deferred accounting for Sherco Unit 3's 2013 depreciation expense.

8. The Commission accepts Xcel's proposed 21-year remaining life of Sherco Unit 3 as a placeholder. Xcel shall have an engineer evaluate Sherco Unit 3 and provide that analysis in its next rate case.

9. Xcel shall provide an analysis and report on the Sherco Unit 3 total costs, insurance recoveries, and costs not covered by insurance in its November 2013 rate-case filing, and it shall provide the completed accounting and report by December 31, 2013.

10. Xcel shall amortize the $5.6 million jurisdictional cost of the Nobles Wind Project, less the $500,000 already recovered, through depreciation over the remaining life of the plant (2013 to 2035). The unamortized balance will be excluded from rate base and a carrying charge is not allowed.

11. Xcel shall amortize the difference between its actual and theoretical depreciation reserves for transmission, distribution, and general assets over a period of eight years.

12. Xcel shall explore with the parties to its next rate case whether there should be any adjustments to depreciation reserves for Xcel's nuclear production assets.

13. The Commission adopts the Department's method, as recommended by the ALJ, to utilize the average growth factor, updated with actual data from January of 2007 through December of 2012, to calculate test year Residential Non-Heating customer counts with a test year residential customer addition of 5,786 customers.

14. The Commission adopts the Department's forecast, as recommended by the ALJ and supported by the Chamber, using the monthly average price changes during the period between January 1998 and June 2012, drawn from the Company's Pre-Filed Forecast Data, for energy price escalators.

15. The Commission adopts the revisions to ALJ Finding 252 as requested by the Department in its Exceptions:

> 252. As shown by the Department, the Company has not proven the reasonableness of a DSM adjustment in this proceeding. The inclusion of a DSM adjustment will under-estimate test-year sales and should not be applied to the sales forecast in this proceeding. ~~the best method of accounting for DSM related savings beyond the first year of a device's implementation, while avoiding an overestimation of the impact of these savings, is to use a four year average to calculate embedded DSM. This approach would increase the sales forecast by 51.161 MWh or $3.0 million in revenue above the forecast resulting from the five year average advocated by the Company.~~

16. Regarding sales to Large Commercial and Industrial Customers, the Commission approves the Department's proposed approach, as recommended by the ALJ, to estimate sales and then make exogenous adjustments, based upon historical data relating to former customers, to reach a final sales figure.

17. The Commission adopts the ALJ's recommendation and determines that the Department's recommendations result in a sales forecast that is reasonable, well-designed, and appropriate for ratemaking in this case.

18. Xcel shall include the following items in its next rate case:

    a. Forecasting data at least 30 days prior to the initial rate case filing;

    b. A comparison to the forecast information in this docket and the Baseload Diversification Study filed on or around July 1, 2013;

    c. Large industrial customer account data in a format that allows interested parties to readily access historical data for all customers;

    d. A spreadsheet, with all links intact, identifying any data inconsistencies with the Company's raw weather data and any modifications made to the raw weather data;

    e. A detailed step-by-step explanation as to how test year revenue was calculated and what commands should be changed if a party wishes to adjust test year sales, adjust customer counts or calculate revenue;

    f. A detailed description of the changes the Company has made to simplify its test year revenue calculation so that persons outside of the Company may verify the accuracy of the calculation; and

    g. A report on the meetings Company representatives have had, prior to filing, with interested parties to explain its revenue calculation process and to cooperatively discuss methods for streamlining the revenue calculation.

19. The Commission approves the $3,200,000-per-year budget increase for a separately funded PowerOn program. The Company shall fund this program by revising the monthly surcharge methodology approved in the Commission's April 5, 2012, Order Approving Cost Allocation, docket E-002/M-10-854. The revised surcharge shall take effect on January 1, 2014, or the effective date of final rates in this rate case. The Company shall segregate and separately track the additional $3,200,000 increase in funding from the other money it collects through the low-income affordability surcharge and shall use this money only for the PowerOn program. The Company shall be responsible for any deficits, i.e., any spending over the $3,200,000-per-year budget, for this part of the Company's PowerOn program.

20. Within 30 days of this order, the Company shall submit in this docket a compliance filing (including revised tariff sheets and a proposal for appropriate customer notice) that implements the Commission's decision to increase the PowerOn budget.

21. Xcel shall amortize the $5.6 million jurisdictional cost of the Nobles Wind Project, less the $500,000 already recovered, through depreciation over the remaining life of the plant (2013 to 2035). The unamortized balance will be excluded from rate base and a carrying charge is not allowed.

22. Xcel shall allocate its Conservation Cost Recovery Charge using the per-kWh method as recommended by the Department. The Commission adopts the Department's proposed changes to ALJ Finding 651 as amended, to read as follows:

651. Although the Company has supported its reasonable method of CIP cost allocation, the Administrative Law Judge acknowledges, for consistent treatment of the allocation of CIP costs for all utilities, consistent with the Commission's decision in Docket E002/M-11-278, that Xcel should use the per-kWh method of allocating CIP costs.

23. Xcel shall reallocate transmission facility costs in this rate case in a manner consistent with its allocation of capacity costs, according to contribution to summer peak demand.

24. Xcel shall set its Customer Charges for the Residential and Small General Service Classes as follows:

Residential Overhead – Standard	$ 8.00
Residential Overhead – Heating	$10.00
Residential Underground – Standard	$10.00
Residential Underground – Heating	$12.00
Small General Service	$10.00

25. The Commission adopts the Department of Commerce's recommended class revenue apportionment as set forth in Direct Testimony and as applied to a revised Class Cost of Service Study, proportionally adjusted based on the final revenue determination. The Commission adopts the technical correction to ALJ Finding 698 as proposed by Xcel:

698. The Company, Department, MCC, XLI, and OAG each provide recommendations regarding the allocation of the revenue requirement among customer classes. The following table reflects their recommendations based on the Company's updated revenue requirement and CCOSS:

Table 18 Comparison of Recommended Revenue Apportionment

Customer Class	Company	Department	OAG	MCC
Residential	~~36.1%~~36.55%	36.06%	~~36.1%~~35.93%	38.11%
C&I Non-Demand	3.86%	3.90%	~~3.9%~~3.77%	4.08%
C&I Demand	58.59%	~~59.0%~~59.03%	~~59.0%~~59.31%	56.90%
Lighting	1.00%	1.00%	~~1.0%~~0.99%	0.90%
Total	100.00%	100.00%	100.00%	100.00%

26. Xcel shall refund the interim rate overcollection at the interest rate of the Company's authorized overall cost of capital, 7.45%.

27. The Commission varies Minn. R. 7825.3300, finding that setting the interest rate on the interim rate refund at the prime rate would impose an excessive burden on ratepayers, that setting a higher interest rate would not adversely affect the public interest, and that setting a higher rate would not conflict with any standards proposed by law.

28. ALJ Findings 846, 848, and 849 are modified as follows:

846. Because the Company seeks to impose a carrying charge on its customers for nuclear refueling outage costs that is equal to its rate-of-return, grossed up for taxes, the Administrative Law Judge concludes that the public interest would not be adversely affected if the Company were required to pay that same rate on interim rate refunds. Both rates are essentially payments for the use of money. The Commission may also note several other points wherein the Company charges a much higher return for under recovery or short-term funds from ratepayers, including under recovery in rider proceedings such as Renewable or Transmission rider and CIP Riders. The Company has failed to explain how the public interest is served by Company paying only 3.25 percent interest on the interim rate refund at the same time imposing a much higher rate on its customers as a carrying charge.

848. The Department demonstrated ~~None of the parties have shown~~ that the first prong is met in the circumstances identified in this proceeding. Department Witness Dale Lusti testified that "enforcement of the rule likely would impose an excessive burden on ratepayers." Mr. Lusti recommended that the Commission look at the facts in this case, including that Xcel has filed multiple cases, along with the difficulty Xcel had in supporting its case and the large difference in the overall rate of return and prime rate to determine whether the Commission concludes that ratepayers would be harmed by enforcement of the rule. ~~The Department re-characterized the first prong when arguing that the standard has been met. The Department asserted that "enforcement of the rule would not impose an excessive burden on ratepayers or the Company (because the Company is repaying to customers what the Company already charged to customers)." Similarly, the OAG asserted that "it is not an excessive burden to require NSP to refund money to ratepayers that was over collected at the same rate it charges ratepayers on behalf of its shareholders." The MCC simply listed a number of facts that it maintains support a variance without addressing the prongs individually.~~

849. ~~Because the parties have not shown that the first prong is met, the Administrative Law Judge recommends that the Commission not grant the variance unless it determines, on its own, that "enforcement of the [average prime interest rate] rule would impose an excessive burden" on the Company or others affected by the rule.~~ The Department has shown that the enforcement of the rule likely would impose an excessive burden on ratepayers such that the first prong is met. The second and third prongs, regarding public interest and conflicting with legal standards, were also met. The Commission varies Minn. R. 7825.3300 to require calculation of the interim rate refund at the Commission-approved overall cost of capital, 7.45%.

29. Xcel shall retain its existing refund mechanism, which provides customer refunds in the event that the incentive compensation payouts are lower than the test-year level approved in rates.

30. Xcel shall evaluate the goals set for its annual incentive program to determine if they are too lenient or if they actually require stretching to meet; the Company shall file the results of the evaluation in its next rate case.

31. Xcel shall supplement its bad debt study. The supplement must address why the Company chose the specific parameters used in the study to identify low-income customers and whether there are any alternative means of identifying low-income customers. It must also compare the parameters used by the Company to the parameters used by other utilities and the Department of Commerce in their studies. The Commission requests that the Company collaborate with the Attorney General on methodology.

32. Xcel shall provide additional reporting of its currently available MAIFI (Momentary Average Interruption Frequency Index) data, such as trend lines, to the extent available. The Commission encourages the Company to add substations enabled with SCADA (Supervisory Control and Data Acquisition) or other similar technology when it is cost-effective to do so. In its compliance filing in this rate case, the Company shall include a proposal for incorporating the requirements of the preceding paragraph into its service quality reports.

33. The Commission approves Xcel's proposed BIS Rider with the modifications recommended by the Department, set forth below:

> 804. The Company proposed that any new revenues from increased load would be retained by Xcel's shareholders between rate cases. ~~The Company also proposed deferred accounting and recovery of the BIS Rider discounts in a subsequent rate case.~~
>
> 808. The Administrative Law Judge recommends that the Commission approve the BIS Rider as modified by the agreement of the Company and the Department~~, but disapprove the Company's proposal for deferred accounting and recovery of the BIS Rider discounts.~~ Additionally, the proposed tariff should be modified with respect to "existing customers" and "new customers" of the Company, as recommended in Dr. ~~Mr.~~ Amit's Surrebuttal testimony.

34. The Commission authorizes Xcel to spread the cost of CR Rider discounts provided to Gerdau Steel among all of its customer classes.

35. The Company's 2008 market loss shall be included in the qualified pension cost for ratemaking purposes; that determination is limited to this proceeding. Further evaluation and evidence of the Company's policy and practice pertaining to past and future pension policies, including surplus, shall be provided in the initial filing of its next rate case.

36. Any previously amortized 2008 market loss amounts that occurred prior to the filing of this rate case are not to be reflected in this or future test-year pension costs.

37. The Company shall not be permitted to include a compensating return on the pension's unamortized asset loss balances.

38. ALJ finding 896 is replaced with the following language:

> ~~896. MCC has demonstrated that it is fair and reasonable to require the Company to include language in its tariff to allow a C&I customer with total peak demand in excess of 1000 KW to be switched to end-of-month billing upon request. MCC's proposal is consistent with the Company's position that it is willing to work with customers who request alternative billing cycles. In addition, the proposal is limited in scope. Furthermore, the Company has failed to provide any specific evidence regarding the alleged "operational, financial and workforce considerations" that cause the Company to oppose the MCC's proposal. For these reasons, the Administrative Law Judge recommends that the Commission adopt the MCC's latest proposal regarding end-of-month billing.~~
>
> 896. Given the Company's willingness to work with customers to achieve reasonable billing solutions and the limited number of customers that can be accommodated without increasing costs, the MCC's proposal should not be adopted.

39. In the initial filing of its next rate case, Xcel shall address the availability of end-of-month billing for C&I customers.

40. In future rate case filings, Xcel shall include for each pension plan schedules of its 2008 market loss amortization, for the entire amortization period, until the 2008 market loss amortization has been extinguished.

41. In the initial filing of its next rate case, the Company shall disclose all past removal and the use of surplus pension assets produced from each of its formulary defined benefit pension plans, qualified and non-qualified.

42. In the initial filing of its next rate case, the Company shall disclose and discuss affiliate XES's and its current and future plans for using any excess surplus pension assets produced from each of its formulary defined benefit pension plans, qualified and non- qualified.

43. The Company has satisfied the Commission Order of May 14, 2012, ordering point 22 from Docket E-002/GR-10-971.

44. In the initial filing of its next rate case, the Company shall provide discussion and support why other stakeholders, other than ratepayers, should not bear pension costs, in general, and more specifically, not bear the pension costs related to the restoration of the fund's market losses.

45. In the initial filing of its next rate case, Xcel shall discuss the extent of any and all of its exploration and evaluation of freezing, or otherwise amending, prior pension benefits and expanding the application of the 5% Cash Balance pension fund formulary to its veteran active employees hired prior to introduction of this formulary benefit (for both the non-bargaining and bargaining unit employees).

46. In the initial filing of its next electric and gas rate case, Xcel shall include a discussion of each non-qualified retirement income plan (both defined benefit and defined contribution type plans) for which cost recovery is sought. The Company shall include in the filing and discussion disclosure of all characteristics of the unqualified plans that cause their unqualified status as well as the supporting documents and actuarial studies relied upon for the derivation of claimed cost.

47. In the initial filing of its next rate case, the Company shall expand upon the information filed under Minnesota Rules 7825.4000(b) and 7825.4100(B), including balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts, for each of the three most recent calendar years relative to the rate case test year. The schedules provided shall be produced in like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15. The Company shall also include explanations of the accounts that have large differences in amounts when compared between actuals and its test-year request (change of ±10 percent or more).

48. In the initial filing of its next rate case, the Company shall include more detailed flight data reports (preferably in live Microsoft Excel electronic format) of its corporate jet trip logs for its most recent 12-month operational period. The report, by flight, must identify the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight. The Company shall include information for the calculation of the requested recovery amount of corporate aviation.

49. In the initial filing of its next rate case, Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of Other Production O&M costs on the basis of the Production Plant.

50. ALJ Finding 663 is modified to read as follows:

> 663. The Company showed the adjusted percent revenue deficiency by customer class using its earlier filed Stratification CCOSS and MCC's Peak Demand method, as well as several other fixed production plant allocation methods. The Company's method produced a Residential revenue deficit of 11.7 percent ~~and a C&I Demand class deficit of 10.0 percent~~. By comparison, the proposed MCC method resulted in a Residential deficit of ~~12.5~~ 18.0 percent ~~and a C&I Demand deficiency percent of 9.4 percent~~.

Footnote 816 in the ALJ's Report is modified to read as follows:

> 816 Ex. ~~60~~61 at ~~19~~15 (Peppin ~~Direct~~ Rebuttal)

51. In the initial filing in its next rate case, Xcel shall provide a complete justification for any rate recovery or deferral of its Prairie Island extended power uprate costs, including at least the following information:

- all work order charges,
- summary of costs by categories, including narrative description of each cost category and support for why costs should be allowed recovery,
- dollar amount of each cost category by year incurred, including total cost amount, and
- any additional information necessary to support the Company's request for cost recovery of the PI EPU cancelled plant.

52. In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects placed in CWIP.

53. In the initial filing of its next rate case, Xcel shall provide a comprehensive discussion of the type of insurance policies, description of coverage and related coverage amounts for which cost recovery is requested for fiduciary insurance and directors and officers insurance. For each policy type, the Company should discuss the relative benefits provided to shareholders, ratepayers, and insured entity; and should provide quantitative support when cost recovery of policy is sought solely from ratepayers. The Company should include an explanation of the bases for insurance cost increases, the degree of increases, and its cost mitigation efforts. Additionally, for each policy type, the information provided should disclose the policy holder, policy beneficiaries, and documentation of accounting treatment of any and all potential insurance proceeds payable to policy holder and/or its beneficiaries.

54. In the initial filing of its next rate case, Xcel shall provide the accumulated FAS 106 and FAS 112 balances for post-employment benefits other than pension and shall include a recent actuarial study on its FAS 106 and FAS 112 benefits, which includes incorporating the 2013 plan changes.

55. In the initial filing of its next rate case, Xcel shall include a discussion of its internal capitalization policy of costs related to transmission studies conducted for projects under contemplation and how its policy conforms to the prescribed FERC accounting under Account 183, *Preliminary Survey and Investigation Charges*.

56. In the initial filing of its next rate case, Xcel shall address the transmission studies included in its rate case and the basis for capitalizing or expensing each transmission study.

57. In the initial filing of its next rate case, Xcel shall incorporate further study of the proper class allocation of economic development discounts.

58. Within 30 days of the date of this order the Company shall make the following compliance filings:

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. These schedules shall include but not be limited to:

a. Total revenue by customer class;

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

c. For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

3. Revised tariff sheets incorporating authorized rate design decisions;

4. Proposed customer notices explaining the final rates, the monthly basic service charge, and any and all changes to rate design and customer billing.

B. A revised base cost of energy, supporting schedules, and revised fuel adjustment tariffs to be in effect on the date final rates are implemented.

C. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

D. A computation of the CCRC based upon the decisions made herein for inclusion in the final order.

E. A schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

F. A proposal to make refunds of interim rates, including interest calculated at the Company's overall cost of capital to affected customers.

59. Comments on compliance filings are due within 30 days of the date they are filed. Comments on the proposed customer notice are not necessary.

60. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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