ISSUE DATE: April 8, 1996

DOCKET NO. E-001/GR-95-601

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

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OF LAW, AND ORDER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Joel Jacobs	Chair
Tom Burton	Commissioner
Marshall Johnson	Commissioner
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Don Storm	Commissioner

In the Matter of the Request of Interstate Power Company for Authority to Change Its Rates for Electric Service in Minnesota

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FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On June 9, 1995, Interstate Power Company (Interstate or the Company) filed a petition, pursuant to Minn. Stat. § 216B.16 (1994) with the Minnesota Public Utilities Commission (Commission) requesting authority to increase Interstate's rates for electric service in the State of Minnesota. The petition sought an increase in electric rates of $4.6 million or 10.3 percent over existing rates.

On July 31, 1995, the Commission issued its ORDER ACCEPTING FILING AND SUSPENDING RATES, a NOTICE AND ORDER FOR HEARING referring the case to the Office of Administrative Hearings, and an Order authorizing Interstate to collect interim rates at the Company's current rate level.

As required by the Notice and Order for Hearing of July 31, 1995, Interstate gave written notice, first approved by the Commission, to each of the municipalities and counties in its service area. Likewise, the Company, as required by the Commission, furnished to each customer, including contract customers, written notice of the proposed increase as a bill insert in form and substance approved by the Commission.

On August 15, 1995, the Company filed copies of the bill inserts giving notice of the hearings.

On August 4, 1995, a prehearing conference was held before Administrative Law Judge (ALJ) Richard C. Luis.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

The Minnesota Department of Public Service (the Department) appeared before the ALJ represented by Dennis Ahlers, Katherine McGill and Brent Vanderlinden, Assistant Attorneys

General, 1200 NCL Tower, 445 Minnesota Street, St. Paul, MN 55101.

The other Intervenor, the Residential Utilities Division of the Office of the Attorney General (RUD-OAG), did not appear at the hearing or file briefs, but remains a party to the proceeding.

B. The Company

The Company was represented by Christopher B. Clark, Staff Counsel, Interstate Power Company, P.O. Box 769, 100 Main Street, Dubuque, Iowa 52004-0769.

III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

Interstate arranged for timely newspaper display ads printed in newspapers of general circulation in the Company's service territory, informing the public about the upcoming public hearings regarding the Company's rate increase request.

Public hearings were held on October 4, 1995 in Albert Lea, Minnesota; October 5, 1995 in Stewartville, Minnesota; and November 2, 1995 in Fulda, Minnesota.

IV. EVIDENTIARY HEARINGS

Evidentiary hearings were conducted on December 14 and 15, 1995.

Subsequent to the hearing, the parties filed late-filed Exhibits 41-47, in response to various requests and inquiries from Commission Staff and the Administrative Law Judge. Those exhibits are all admitted to the record.

V. THE SETTLEMENT AGREEMENT

On December 4, 1995, the parties submitted a Settlement Agreement which resolves all but four of the disputed issues: Purchased Power Contracts, Return on Equity, Interruptible Discount, and Declining Block Rates. In the Settlement Agreement, the parties asserted that the Settlement Agreement is fully supported by the evidence in this case. The Settlement Agreement references the relevant supporting evidence. The parties also stated that the Settlement Agreement, along with the Commission's separate determination on the remaining contested issues, will result in a revenue requirement for Interstate that is just and reasonable, and will result in Interstate providing adequate service to its customers at the lowest possible rates, consistent with the need of Interstate's investors to earn a fair and reasonable return on their investment.

In his Findings of Fact, Conclusions and Recommendation, the ALJ stated that he reviewed the Settlement Agreement along with the record evidence filed in support of the Settlement Agreement and concurs with the parties' view that the Settlement Agreement is fully supported by the record evidence and is in the public interest. The ALJ also found nothing contrary to law or Commission precedent in the Settlement Agreement. Therefore, the ALJ adopted the settlement agreement in its entirety.

VII. ADDITIONAL AGREEMENTS

The parties also agreed on numerous issues not specified in the Settlement Agreement. Those issues, and the agreements regarding them, are specified in late-filed Exhibits 44 and 45. The Administrative Law Judge adopted these agreements in their entirety.

VIII. PROCEEDINGS BEFORE THE COMMISSION

On February 22, 1996, the ALJ filed his final report and recommendations.

On March 6, 1996, the Commission heard oral arguments from the parties and on March 8, 1996, the Commission met to consider this matter.

Upon review of the entire record of this proceeding, the Commission makes the following Findings of Fact, Conclusions of Law, and Order.

FINDINGS AND CONCLUSIONS

IX. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. § 216B.01 and 216B.02 (1994). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1994).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1992) and Minn. Rules, part 1400.0200 et seq. (1995).

IX. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7829.3000, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of the Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all the parties. The filing should include an original, 15 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 15 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1994), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 60 days of filing is deemed denied. Chapter 224, Section 77 of the 1995 Minnesota Session Laws, Minn. Stat. § 216B.27, subd. 4 (1994).

XI. THE COMPANY

Interstate Power Company is an investor-owned combination electric and gas utility engaged principally in the generation, transmission and distribution of electric energy and the transmission and distribution of natural gas in a 10,000 square mile service area in northeast and north central Iowa, southern Minnesota, and northwestern Illinois.

Interstate serves over 161,900 retail electric customers, of which over 39,000 are located in Minnesota. The largest community served in Minnesota is Albert Lea, with a population in excess of 19,000.

For the year ending December 31, 1994, Interstate derived approximately 18 percent of its total electric revenues from electric sales in Minnesota.

XII. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1994) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change." Under Minn. Stat. § 216B.03 (1994), every rate made, demanded or received by any public utility "...shall be just and reasonable.... Any doubt as to the reasonableness should be resolved in favor of the consumer."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. 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 (Minn. 1987). In the Northern States Power case the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such service at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate case proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

XIII. THE TEST YEAR

Interstate has selected January 1, 1994 to December 31, 1994, adjusted for known and measurable changes, as the test year to be used for determining its revenue requirement.

No party objected to the Company's test year and the ALJ found that the Company's proposed test year is reasonable.

The Commission finds that the Company's use of a 12-month historical test year ending December 31, 1994 was appropriate in this proceeding.

XIV. THE SETTLEMENT

Settlement discussions between the parties resulted in the Company and the Department reaching agreement on most of the financial and rate design issues in the case. The Settlement Agreement was filed December 4, 1995. The RUD-OAG intervened in this matter but due to resource constraints took no part in the proceedings. Accordingly, it did not participate in settlement discussions, was not a signatory to the agreement, and neither supported nor objected to the agreement.

The settlement is offered as the product of compromise. Settlements are encouraged under Minn. Stat. § 216B.16, subd. 1a (1994), which requires the Commission to consider and deal with them as a package. The statute recognizes that a settlement is an integrated whole whose individual provisions are mutually dependent and may be linked in ways that are not immediately apparent. Therefore, the statute gives any settling party the right to reject any modification the Commission makes to a settlement and to return to hearing.

The parties agreed that the Settlement Agreement significantly reduced the $4.6 million increase Interstate had initially proposed, but noted that the final revenue requirement could not be determined until the remaining financial issues had been resolved.

The Administrative Law Judge examined the Settlement, and each issue settled, for reasonableness and support in the record. He found that the Settlement was supported by substantial evidence and that accepting it would be in the public interest. He recommended accepting it without modification.

XV. SETTLEMENT MODIFIED AND ACCEPTED

A. Structure and Content of the Settlement

The Settlement Agreement, which is attached, proposed to resolve the following issues:

1. Financial Issues

a. Cash working capital
b. Unamortized rate case expense in rate base
c. Old CIP unamortized balance
d. CIP deferred amortization
e. Plant additions
f. Rate case expense
g. Economic development

h. Allocation of A and G expense to non-regulated activities
i. CIP tracker amortization
j. Test year CIP
k. Conservation cost recovery charge (CCRC)
l. Property taxes
m. Manufactured gas plant (MGP) clean-up costs
n. Interest synchronization
o. Test-year sales and revenues
p. Capital structure

2. Rate Design and Cost of Service Study

a. Revenue apportionment among classes
b. Street lighting and security lighting
c. Seasonal and time of day rates
d. Customer charges
e. Method of adjusting class revenues to the Commission -approved revenue requirement

3. Other Areas of Agreement Addressed in Settlement: Filing Requirements for Next Rate Case

a. Cost benefit study re: demand-metered service for residential customers
b. Cost benefit study re: adding three-part demand-metered rate to two-part single-phase farm tariff
c. Basic service charge reflecting differences in metering costs by type of rate structure
d. Computation of the competitive discount for Farmstead Foods, Inc.
e. Computation of energy charges for stored heat, space heating, and controlled water services

B. Commission Modifications to the Proposed Settlement

1. CIP Tracker Amortization

The parties to the Settlement resolved all outstanding concerns on the level of Conservation Improvement Program (CIP) costs to be included in rate base and expense. The parties agreed to exclude $30,021 of prior rate case CIP costs and $234,699 of CIP tracker costs from rate base. The parties agreed to include no CIP costs in Interstate's rate base. The parties agreed to increase the costs for annual CIP expenditures by $330,605 to $933,187 reflecting Interstate's latest CIP budget approved by the Commissioner of the Department of Public Service. The parties also agreed to include for recovery an amortization of the October 30, 1995 CIP tracker balance of $791,565 over a five year period. The Commission finds the parties' foregoing agreement on CIP cost recovery appropriate and approves it.

As part of the Settlement agreement on CIP, the parties also agreed to remove the October 30, 1995 balance of $791,565 from the tracker and recover carrying charges on this balance as an operating expense. Carrying charges were computed on the monthly declining balance before tax over the five-year amortization period. Using this method, a total of $221,172 of carrying charges were to be recovered over a five year period. The Commission finds this method inappropriate for two reasons:

- First, the parties' use of a ***before-tax*** balance to compute carrying charges overstates Interstate's carrying costs. Interstate's expenditures for CIP are deductible for tax purposes. Therefore, Interstate's actual costs, net of the tax savings, are approximately 41 percent less than the before-tax costs. The Commission finds that the appropriate CIP balance to be used in calculating carrying costs is the ***after-tax*** CIP balance.

- The Commission also finds that the parties' agreement to remove the October 30, 1995 tracker balance from the tracker is unnecessary. The parties' intent to increase cost recovery to reduce the tracker balance is appropriate so that Interstate does not continue to carry a large balance in its tracker. However, zeroing out the tracker is not necessary to reduce the tracker balance.

An alternative approach that is less complicated and cumbersome would be to leave the CIP costs in the tracker and raise the recovery level by an imputed amortization amount. The parties have agreed to amortize the $791,565 balance over five years. The annual amortization of $158,313 will be added to the annual CIP budgeted amount of $933,187. Rate recovery will then be based on an expense level of $1,091,500. Over time the tracker is expected to be reduced by the additional expense level represented by the imputed amortization of $158,313.

The Commission finds it reasonable to leave prior CIP costs in the tracker along with on-going CIP costs to simplify the review and accounting for CIP expenditures. Carrying charges will accrue on the monthly CIP tracker balance on an after-tax basis the same as the parties agreed to for on-going CIP expenditures. The Commission will require Interstate to file its determination of the CIP cost recovery factor (the per kWh amount to be used for crediting monthly revenues to the CIP tracker account) within thirty days of the date of this order.

2. Customer Charges

As part of the settlement, the Company and the Department agreed to increase the customer charges for all customer classes. Customer charges, which apply without regard to usage, are designed to recover costs that do not vary with usage. The Commission will modify the settlement and require that customer charges remain at current levels across the board.

In the past several rate cases in which the Commission has examined customer charges, it has expressed grave reservations about permitting greater reliance on these ratemaking devices.[1] Customer charges tend to confuse and alienate customers, neutralize conservation incentives, burden low income households, and perpetuate pricing structures ill-suited to competition. For all these reasons, the Commission will reject the settlement's customer charge provisions.

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[1] In the Matter of the Application of Minnegasco, a Division of Arkla, Inc. for Authority to Increase its Rates for Natural Gas Service in Minnesota, Docket No. G-008/GR-93-1090; In the Matter of the Application of Minnesota Power for Authority to Increase its Schedule of Rates for Retail Electric Service in the State of Minnesota, Docket No. E-015/GR-94-1; In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota, Docket No. G-001/GR-95-406.

The Commission continues to believe that the cardinal goals in residential ratemaking are making rates understandable, making them easy to administer, and maintaining public confidence in their fairness. Customer charges work at cross purposes with these goals.

The distinction between fixed and variable costs underlying the customer charge is not familiar or readily understandable to most consumers. All providers of goods and services have embedded costs. Non-regulated retailers, however, factor these costs into unit prices, as opposed to assessing surcharges to recover them on a per-customer or per-transaction basis. Consumers are accustomed to having embedded costs factored into unit prices; to the maximum extent possible, residential utility service should be priced in the same way.

Another concern in the residential context is that unit pricing offers some measure of rate relief to low income, low usage households. While the significance of that relief was not developed in the record of this case, the Commission's institutional experience is that every utility's customer base includes some low income, low usage households for whom large customer charges are burdensome.

A concern applicable to all ratepayer classes is that large customer charges tend to conflict with the statutory mandate to set rates to encourage conservation. Minn. Stat. § 216B.03. One of the most powerful tools for heightening conservation-consciousness is maintaining a clear link between consumption and cost. While this link must sometimes be tempered to meet other ratemaking goals, it remains the starting point for setting rates to encourage conservation.

Finally, customer charges, as creatures of regulatory theory, are unlikely to survive any transition from rate of return regulation to competition. While the potential for successful competition in different energy markets is still unclear, the Commission is committed to exploring that potential. Meanwhile, utility regulation continues to move toward market-based strategies to accomplish its objectives. Customer charges are inconsistent with both developments, and the Commission will not permit increased reliance on them during this period of re-evaluation.

For all these reasons, the Commission concludes it must modify the settlement to hold customer charges at their existing levels.

C. Commission Analysis and Action

The parties included in their Settlement Agreement support from the record for their resolution of every issue. They also explained certain issues on the record orally at the evidentiary hearing and made their witnesses available for questioning by the Administrative Law Judge and Commission staff, to clarify the evidentiary basis for settled positions if necessary. In addition, at the request of the ALJ, the parties submitted two late-filed exhibits (Exhibits 44 and 45) clarifying the issues resolved in the Settlement Agreement.

Since the Commission must base its rate case decisions on the record, these steps substantially increased the Settlement's value and credibility. Minn. Stat. § 14.60, subd. 2 (1994). While the Commission conducts an independent review of the record before acting on any settlement, it is reassuring and helpful for the parties to demonstrate, as they have here, that the content of the record was central to their resolution of every issue.

Having reviewed this matter carefully, the Commission will accept and adopt the Settlement, modified with respect to two issues noted above: CIP tracker amortization and customer charges. The Commission finds that the Settlement Agreement, with the two exceptions noted, is supported by substantial evidence, represents a just and reasonable resolution of the individual issues settled, and promotes the public interest.[2] Together with the additional items agreed upon between the parties and the Commission's separate determination on the remaining contested issues, the Settlement will result in just and reasonable final rates.

XVI. OTHER ISSUES AGREED UPON OR UNCONTESTED

In reviewing this matter and late filed exhibits 44 and 45 in particular, the Commission finds that the Settlement Agreement did not cover all that the parties actually agreed upon or have not contested. The ALJ found sufficient support exists in the record on all such issues and recommended that it is appropriate to approve them in addition to those covered in the Settlement Agreement.

A. Financial Issues

In addition to issues covered in the Settlement Agreement, Interstate and the Department agreed to various financial adjustments and amounts included in Interstate's proposed test year data. Among the issues and amounts agreed to are as follows:

[2] In addition, the parties have agreed that the Commission need not determine which party's Class Cost of Service Study (CCOSS) should be used in this matter. See Section XV, B, 1.

1. **Rate Base**

- customer advances . . . . $(1,295)
- retirement work in process . . . . $ 114,913
- customer security deposits . . . . $(252,109)

2. **Income Statement**

- other operating revenues $1,372,794
- transmission expense $1,039,461
- distribution expense $3,316,740
- customer service expense . . . . $ 527,319
- customer accounting $1,258,376
- depreciation $5,211,392

The Commission accepts these amounts as agreed to by the parties and recommended by the ALJ.

B. Rate Design Issues

1. **Class Cost of Service Study (CCOSS)**

Interstate and the Department did not use the same methodology in developing the Class Cost of Service Study (CCOSS). However, in their Settlement Agreement, the parties stated that a Commission determination of which should be used was not necessary. The Commission agrees that the practical differences resulting from the different studies is negligible in this case. Therefore, the Commission need not and will not decide that issue in this case.

2. **Compliance With Prior Rate Case Orders**

In the Commission's FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, issued June 12, 1992, in Docket No. E-001/GR-91-605, the Commission required that Interstate make certain filings before, or at the time of, the Company's next rate case filing. These filings included:

- detailed rate case expense documentation
- refiling of the Company's Conservation Plan, including a discussion of the "conservation continuum" in its discussion of goals and objectives
- plan for estimating actual energy savings of direct impact demand-side management (DSM) programs
- calculation of revenues lost due to conservation for each year to be filed by March 1 of the succeeding year
- evaluation of the capacity and energy benefits for each of the Company's CIP programs
- 1991 load data with proposals for new rates based on the data
- thorough discussion of alternatives for addressing the energy needs of low income people
- proposal for a new space heating rate
- further information on the Large Power & Light rate schedule verifying the reasonableness of a reactive demand charge of $0.49 per kVAR in excess of 50 percent of the maximum kW metered during the month

- additional information on the direct cost impact of supplying kVARs on its system
- multi-period time of day rate applicable, at a minimum, to the municipal pumping class
- Class Cost of Service Study using the Company's new load research to determine a multiple-coincident peak allocator for allocating production plant and other costs
- incorporation of all changes to the Company's Class Cost of Service Study adopted by the Commission in Interstate's 1992 rate case
- full Class Cost of Service Study, including the relevant working papers

The Commission finds that Interstate has filed all the information and addressed all the issues raised in the Commission's Order, issued June 12, 1992 in Docket E-001/GR-91-601.

3. Miscellaneous Changes in the Electric Service Tariff

Interstate proposed changes to its electric service tariffs regarding the following items: 1) revisions to the availability provisions of the Large Power & Light Rate and the three-phase farm rate; 2) elimination of the Residential Conservation Rate Break Credit; 3) an increase in the reconnection charges; and 4) elimination of the residential electric heat tariff. The Department either supported or did not oppose those changes.

The Department suggested additional tariff changes that the Company accepted: 1) correction of the demand and energy charges for the Residential Rate 163; and 2) resolution of the inconsistency between Rate 447 and Rate 449.

a. Revisions to availability provisions for certain rate schedules

Interstate proposed to clarify the availability of the Large Power & Light rate so that the tariff clearly specifies which tariff applies to customers that no longer qualify for this rate. The Company also proposed to clarify when three-phase farm customers qualify for the Large Power & Light rate.

The Department did not address or oppose these proposals. The ALJ found that ample support exists in the record to adopt these provisions. The Commission also finds the proposed revisions appropriate and will approve them.

b. Elimination of the residential conservation rate break credit

Interstate proposed to discontinue the conservation rate break credit for residential customers. It indicated that in spite of the availability of the credits for the Company's Minnesota jurisdiction only, there is no appreciable difference in the average monthly consumption of residential customers among the states of Minnesota, Illinois, and Iowa.

Interstate indicated that about 2.5 percent of its residential customers are identified as low income and receive the conservation rate break credit, while about 6 percent are identified as low income only. Thus, the credit is not effectively targeted at low income customers.

The Commission will approve the Company's proposal to discontinue the conservation rate break for residential customers. Given the conservation activities targeted at low income individuals within the Company's service area, and the inability of the Company to ascertain the value of the credits, the Commission supports the Company's proposal to cancel the credits at this time.

c. Reconnection charges

Interstate proposed to increase its current charges for reconnections following temporary disconnections. The Company currently charges the actual costs of reconnection, but no less than $6.00 per reconnection. Interstate proposed to charge "the greater of $35.00 per reconnection or the customer's normal monthly customer charge times the number of consecutive months for which service was disconnected."

The factual support for these costs is provided in Schedule 14. The proposed changes are unopposed by the Department and the ALJ recommended adoption. For these reasons, the Commission will adopt the changes to the reconnection charges as proposed by the Company.

d. Elimination of residential electric heat tariff

Interstate proposed to eliminate its residential electric heat tariff and to allow customers currently on the tariff to take service under the blocked seasonal feature that the Company proposed for the non-summer season under its standard residential rate. Interstate argued that the electric space heat rate does not accurately reflect seasonal costs.

The Department supported the Company's proposal to eliminate the separate residential electric space heat rate. The Department indicated that the current space heat rate features seasonally differentiated rates. Therefore, it recommended that the separate rate for electric space heat customers be eliminated and that these customers be transferred to the residential tariff with seasonal rates (Rate 161).

Since the Commission has adopted the Company's proposal for a seasonal residential rate with a non-peak winter season declining block structure, the Commission finds it appropriate to eliminate the separate space heat rate for residential customers.

e. Correction of demand and energy charges for Residential Rate 163

The Department argued that Interstate made certain errors in designing its residential demand metered Rate 163. Specifically, the Department indicated that Interstate subtracted the amount of the revenue adjustment for under-collected customer costs from the generation, transmission, and distribution demand costs it allocated to seasons. The Department argued this is an error, since the basic service charge for this tariff recovers customer costs.

The Company agreed that it had made an error in the design of Rate 163. It agreed, in the development of final rates resulting from this proceeding, to correct this error. The Commission finds the Department's proposed correction of this rate to be appropriate and will approve it.

f. Resolution of the inconsistency between Rates 447 and 449

Rate 447 is the standard tariff for Large Power & Light customers. It features a monthly basic service, energy, and demand charge. Rate 449 is the Optional Large Power & Light, Time of Use

(Off-Peak) rate. It features a monthly basic service charge, and on- and off-peak energy and demand charges.

The Department indicated that there was an inconsistency between the seasonal energy charges Interstate proposed for the non-summer season for Rate 447 and those proposed for Rate 449. Specifically, the Company proposed a non-summer energy charge for Rate 447 that was lower than the per kWh energy charge for the non-summer off-peak energy charge for Rate 449. However, based on the indicated rates per MWh in the Company's workpapers, the Department noted that the winter Rate 447 energy charge should be slightly greater (.23 percent) than the winter off-peak rate for Rate 449. The Department argued this slight difference should be maintained in the rate design.

In rebuttal testimony, the Company agreed that there was an inconsistency between Rates 447 and 449, as initially proposed by the Company. Thus, the Company agreed to correct the rates, based on the Department's suggestions, in the development of final rates resulting from this proceeding. The Commission finds the correction proposed by the Department and agreed to by the Company to be appropriate and will approve it.

XVII. REMAINING CONTESTED FINANCIAL ISSUE

A. Long Term Purchased Power Contracts

1. Background

In the week prior to filing its August 15, 1991 petition to increase rates in the previous rate case (Docket No. E-001/GR-91-605), Interstate entered into three long-term power purchase contracts for a total of 230 megawatts (MW). The contracts are with Iowa Public Service (IPS), United Power Association (UPA), and Minnesota Power (MP). The contracts became effective on May 1, 1992 and will remain in effect until April 30, 2001.

In that rate case, the Commission disallowed recovery of an amount equal to the price paid by the Company for 100 MW of power purchased pursuant to the Company's contract with Iowa Public Service (IPS). The Commission did so based on three findings: 1) that Interstate's three purchase power contracts imprudently resulted in 100 MW excess reserve; 2) that this amount (100 MW) was not "used and useful"; and 3) that the IPS contract price was an appropriate proxy to determine the dollar value of the 100 MW capacity that it excluded.[3]

The reason the three purchased power contracts addressed in the previous rate case are still relevant is that they are long-term contracts that will not expire until 2001. As such, the Company continues to incur costs associated with them, in excess of $23,000,000 annually. Interstate has requested that Minnesota's jurisdictional portion of those annual contract costs be

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[3] In the Matter of the Application of Interstate Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota, Docket No. E-001/GR-91-605, ORDER AFTER RECONSIDERATION (October 19, 1992)at page 9 referring to the Commission's June 12, 1992 FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER in this matter, pages 22-24.

included as a test year operating expense. The recoverability of those costs is at issue in this case.

2. Interstate's Proposal

Interstate argued that there is no excess capacity at this time due to load growth it has experienced since the previous Order. Therefore, the Company argued, no disallowance of any purchased power contract costs is appropriate.[4] Allowing 100 percent of these costs is appropriate, according to the Company, because this amount of purchased power is necessary to allow for future load growth which, the Company asserted, the record indicates is likely to occur. By contrast, without this additional capacity the Company would risk incurring severe penalties from the Midwest Area Power Pool (MAPP) if the Company's reserves fall below 15 percent. In addition, the Company argued, disallowance of any of these costs would penalize the Company for aggressively pursuing demand side management (DSM).

As an alternative to 100 percent recovery, the Company argued that any disallowance amount should be limited to the cost of 33 MW. The Company reached the 33 MW figure by taking the 100 MW disallowed in the last rate case, subtracting the 92 MW load growth the Company has experienced (peak usage of 919 MW in 1988; 1,011 peak usage in 1995), which produces an 8 MW difference, then adding 25 MW of additional capacity purchased from Minnesota Power during this time period.

Interstate criticized the Department's proposal to disallow 100 MW. The Company stated that the Department's method of calculating the 100 MW allows only 20 MW for future growth. In the face of the 92 MW growth that Interstate has experienced, the Company argued that this 20 MW cushion was unrealistic and would subject it to severe penalties from MAPP if the Company's reserves fell below 15 percent.

3. The Department

The Department noted that the Commission finding in the previous rate case that Interstate acted imprudently when it entered into three long-term purchase power contracts cannot be reargued in this case. Therefore, according to the Department, the only issue left for determination in this case is the amount of excess capacity on Interstate's system as a result of its ongoing obligations under the imprudently incurred purchase power contracts.

The Department calculated the Company's 1995 excess capacity by comparing the Company's required capacity with its available capacity. The Department calculated the Company's required capacity as follows: starting with the Company's highest peak usage (1,011 MW established in July 1995), the Company added the 20 MW difference between its off-system Sales (95 MW) and its sale of capacity back to UPA (75 MW).[5] To that sum (1,031 MW), it added MAPP's 15

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[4] The capacity purchase from Minnesota Power has increased by 25 MW since the last rate decision in Docket No. E-001/GR-91-605. The total capacity purchased annually by the Company pursuant to the three contracts at this time, therefore is 255 MW.

[5] In the test year, Interstate sold 75 MW back to United Power Association (UPA) at a rate roughly 16.5 percent of the rate that the Company paid UPA for the capacity in the first

percent reserve margin (155 MW) to reach a required capacity of 1,186 MW. The difference between the required capacity (1,186 MW) and the Company's available capacity (1,306 MW) was 120 MW. DPS Exhibit BP-5.

The Department recommended that the Commission disallow 100 MW, as it had done in the prior rate case, arguing that the Company's forecasts show it will have excess capacity greater than 100 MW through the year 2000.

In valuating the excess capacity that it recommended be disallowed from Interstate's test year expenses, the Department used a method different from the Commission's approach in the previous rate case. In that case, the Commission used the contract amount for 100 MW in one of the long-term purchased power contracts (the contract with Iowa Public Service) as a proxy for the value of the 100 MW excess capacity. In this case, the Department calculated the cost with reference to three components: 1) a demand component; 2) a wheeling component; and 3) an energy cost saving component. The Department added the demand component [$1,580,754] and the wheeling component [$126,334] for a total demand-related cost of $1,707,088. Then, the Department subtracted the energy cost savings [$773,691] from the total demand-related cost to arrive at a test year cost of excess capacity of $933,397.

Finally, the Department recommended that the Commission decrease Interstate's test year "other" operating revenues by $125, 487 to account for the below cost sale of capacity back to UPA. The Department indicated that since it was recommending that the cost of 100 MW of contracted power be excluded from test year costs, it would be consistent to treat revenue from the resale of that power similarly and exclude it from test year revenues.

4. The ALJ

The ALJ agreed with the Department that Interstate's test year "other" operating revenues should be reduced by $125,487 to account for the below cost sale of capacity back to UPA. The ALJ also agreed with the Department's method of valuating the excess capacity. The ALJ dismissed the Company's argument that disallowance of any amount would penalize its demand side management (DSM) achievements, noting that the Company is required to pursue those efforts in any case. While finding some disallowance appropriate, however, the ALJ disagreed with the Department about the level of that disallowance, finding that the appropriate level was 50 MW.

In reaching the 50 MW figure, the ALJ calculated as follows: starting with the known and measurable peak demand of 1,011 in 1995 and the Company's established capacity of 1,306, the ALJ stated that this would provide a 22.5 percent reserve. The ALJ reasoned that this 22.5 percent figure (50 percent greater than the 15 percent required by the MAPP) was too high for ratepayers to absorb appropriately. The ALJ calculated further that a 50 MW disallowance would leave a reserve of 245 MW or 18.8 percent and concluded that this level would provide an adequate reserve and absorb any potential growth in demand during the regulatory horizon.

5. Commission Analysis and Action

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place.

a. Relevance of Prior Order

The usefulness of the Commission's excess capacity decision in the previous rate case warrants some discussion. In that Order, the Commission made two separate findings: 1) that the Company had entered into three long-term contracts imprudently and 2) that the excess capacity resulting from the imprudently entered contracts was 100 MW. It is the first finding (that the Company entered the three contracts imprudently) that is binding in this action and cannot be relitigated. This is appropriate because the facts on which it was based (the information the Company had before it at the time it decided to enter into the contracts) have not changed.

The second finding cited, the specific amount of the Company's excess capacity, is not binding in this matter, and should not be used either as a floor or ceiling for the amount of excess capacity that may be found in this matter. Nor is it even a helpful starting point, as used by the Company, in calculating the amount of excess capacity. The finding of 100 MW excess capacity in the previous case has no binding effect upon this matter because a determination of excess capacity depends on the facts at hand when that determination must be made and those facts (primarily the available capacity, the peak system demand, and circumstances providing a basis for determining an appropriate reserve amount) will differ from case to case.

b. Excess Capacity Finding

Interstate: The Commission does not accept Interstate's overly narrow approach to determining excess capacity. The Company treated the 100 MW excess capacity finding of the prior case as the starting point of its analysis, subtracted what it termed load growth (92 MW) and claimed that this proved that the excess capacity found in the previous case had been virtually eliminated. The error in this method is that it treats the previous finding (100 MW of excess capacity) as the ceiling and refuses to take a comprehensive new look at the Company's entire energy picture.

The ALJ: The approach taken by the ALJ to determine the level of excess capacity in this case is more appropriate. With the exception of a relatively minor adjustment made by the Department and discussed below, the Commission concurs in the ALJ's analysis. The ALJ started his analysis looking at the Company's overall available capacity in 1995: 1,306 MW. In that regard, all parties, including the Company, agreed that the Company's available capacity in the test year was 1,306 MW. From that number (1,306 MW), the ALJ subtracted the 1995 peak demand figure (1,011 MW) to reveal the Company's excess capacity: 295 MW.

At that point, however, a minor math error in calculating the percentage of reserve led the ALJ to understate the Company's reserve, excess capacity. The ALJ correctly stated the Company's peak demand (1,011 MW) and its capacity (1,306 MW) but then miscalculated the Company's reserve excess capacity resulting from those figures as 22.5 percent. ALJ's Findings of Fact, Conclusions of Law and Recommendation at page 33. The proper figure (percentage of reserve) based on those numbers is 29.2 percent.[6]

Based on his belief that 295 MW represented a 22.5 percent reserve, the ALJ felt that some disallowance was necessary but that the Department's request to disallow 100 MW would be excessive. Instead, the ALJ found that disallowance of 50 MW would reduce the reserve to 18.8 percent, a level of reserve the ALJ felt ratepayers could be reasonably required to fund. The ALJ's reliance upon figures resulting from the math error noted above was critical in his conclusion that disallowance of only 50 MW was appropriate. Had he realized that 295 MW represented a 29.2 reserve, it is likely that he would have approved disallowance of the full 100 MW recommended by the Department. Using the ALJ's analysis, such a disallowance (100 MW) would result in 195 MW funded excess capacity above the peak demand (1,011 MW) or a 19.2 percent reserve.

The Department: The ALJ 's analysis, described above, essentially followed the Department's. However, the Department adjusted the Company's system demand upward by factoring in off-system firm sales [95 MW] minus the sale back to UPA (75 MW) and thereby increasing the system peak demand figure [1,011 MW] by 20 MW to 1,031 MW. To that figure, the Department added the required MAPP 15 percent reserve [155 MW] to calculate a figure the Department termed "required capacity": 1,186 MW. By subtracting the required capacity [1,186 MW] from the available capacity [1,306 MW] the Department reached its view of the Company's excess capacity, 120 MW. Disallowing 100 MW (as recommended by the Department) would leave the Company with a ratepayer supported reserve of 175 MW (MAPP reserve of 155 MW plus 20 MW excess capacity not disallowed) which is 17 percent above the adjusted demand [1,031 MW].

Commission Finding: the Commission finds that disallowance of 100 MW excess capacity in this case is conservative and amply warranted under several rationales.

Rationale 1: The Department started conservatively, accepting a peak [1,011 MW] that everyone acknowledged resulted from highly abnormal weather conditions, conditions which, based on history, are highly unlikely to recur within the years the rates adopted in this Order will be in effect. To that number, the Department makes a 20 MW **upward** adjustment of 20 MW to reflect off-system sales activity (off-system firm sales minus the proceeds of the sale back to UPA). This upward adjustment was not adopted by the ALJ and appears unwarranted because the 20 MW in question represents power that is clearly not necessary to meet the Company's load. Even with that upward adjustment, the Department's recommendation to disallow 100 MW leaves a 17 percent reserve. Based on the Commission's discussion of reasonable reserve margins below, that the Department's figure is within the range of reasonableness.

Rationale 2: In recommending disallowance of 50 MW, the ALJ's figures (corrected as to the math error and not including the Department's upward 20 MW adjustment) left the Company a

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[6] The difference between capacity (1,306 MW) and peak demand (1,011 MW) equals 295 MW. To determine the percentage by which capacity exceeds peak demand, therefore, one divides the 295 MW by the peak demand (1,011 MW) which yields a quotient of 29.2 percent. The ALJ's math error was in dividing the excess capacity (295 MW) by the ***capacity*** (1,306 MW) rather than the ***peak demand*** (1,011 MW).

reserve (above the amount required to meet peak system demand) of 29.2 percent. Again, using the ALJ's analysis (corrected as to the math error, etc.) disallowance of 100 MW would leave the Company a 19.3 percent reserve.

Rationale 3: For its part, the Commission has calculated a reasonable level of disallowance, including a reasonable reserve margin, as follows: 1995 peak system demand [1,011 MW] plus the required MAPP reserve for that amount (15 percent of peak demand or 152 MW) equals 1,163 MW of Total Required Capacity. That figure [1,163 MW] subtracted from Available Capacity [1,306 MW] yields a capacity above what is required in the amount of 143 MW. Given that level of excess capacity, disallowance of 100 MW would leave 43 MW as Additional (non-MAPP) Reserve. Adding the Additional Reserve [43 MW] to the MAPP Reserve [152 MW] results in a Total Reserve of 195 MW which a represents an overall reserve of 19.3 percent.[7]

How Much Reserve (Capacity Above Peak Demand) is Reasonable?

In requesting recovery for all the costs associated with its three long-term purchased power contracts, the Company has in effect proposed that the Commission find a 29.2 reserve margin reasonable. In the alternative, the Company has acknowledged that disallowance of 33 MW might be reasonable. This amount of disallowance would leave the Company with a reserve margin of 25.9 percent.[8] The Commission finds these figures unreasonable and will reject them.[9]

In requesting that ratepayers fund reserve capacity (capacity exceeding peak demand), the utility (as with all elements of its case) bears the burden of showing that its request is reasonable. Part of that burden includes showing, for example, the actual consequences of not maintaining the requested reserve. In this case, Interstate has alluded to but not established the consequences of failing to maintain the reserve margin it proposes. In its brief after the close of the record, the Company referred for the first time to the "severe penalty" it alleged it would incur from MAPP if it did not maintain reserves of at least 15 percent of its peak demand. It is fundamental that briefs are not record evidence and vague unsupported references to a "severe penalty" are unpersuasive. In short, the Company has provided no basis to assess the seriousness of the alleged penalty threat, how it is assessed, and the time and means available to the Company to avoid the penalty by

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[7] This figure 19.3 percent is the same reserve margin that the ALJ would have reached, as noted above but for the math error in his calculations.

[8] Given the 295 MW of excess capacity found by the ALJ and accepted by the Commission as noted above, disallowance of 33 MW would leave 262 MW excess capacity paid for by the ratepayers. Since the 1995 peak system demand is 1,011 MW, 262 MW would represent a 25.9 percent reserve margin.

[9] The Commission notes that as in selecting rates of return, the reserve margins approved in rate cases do not constitute precedent in the next rate case because the circumstances of each case will differ, even for the same utility. For example, the peak demand level adopted and the intensity of pressures upon that level reasonably anticipated over the coming years will vary from case to case. Likewise, the severity of consequence for failing to maintain any particular reserve margin and the options for avoiding those consequences may well vary from case to case.

curing the non-compliance.

In addition, the reasonableness of the requested reserve margin must be assessed in light of the likelihood that the Company will experience demand surpassing the new peak level, which was established under extraordinary weather conditions in the summer of 1995. The Company's argument jumps over the aberrational nature of the peak period and would have the Commission view the new peak as due to systemic load growth when in fact it was primarily weather (heat) driven. If the Company had shown that demand in the peak period was due to growth rather than a fluke of nature, the likelihood of actually experiencing and exceeding the peak demand would be increased and hence the reasonableness of providing a cushion increased. In this case, however, the record suggests that the peak is due to aberrational weather. By the Company's own forecasting, actual growth in demand is not expected to approach the new peak demand level until 1999. Based on the record, then, the Company has provided no reasonable basis for concluding that the Company will exceed its new peak system demand in any significant fashion in the foreseeable future to warrant the sizeable reserves it seeks.

In these circumstances (imprudent entry into three long-term purchased power contracts for a total of 230 MW capacity and failure to show reasonable need for 100 MW of that capacity), the Commission will allow the Company to recover the costs for only 130 MW of the capacity in question. The Commission notes that under its analysis (and that of the ALJ, rightly understood) this disallowance of 100 MW of that capacity will leave the Company with a 19.3 percent reserve margin above the new system peak demand. Based on the foregoing analysis, this reserve margin is clearly within the range of reasonableness.

On the valuation question, the Commission clarifies that it accepts the Department's method of valuating the disallowed capacity. As noted previously, this method of valuation differs from what the Commission did in the previous Interstate rate case. However, in that case, the Commission did not reject the idea that energy savings (avoided fuel and O&M costs) should be credited against the disallowed costs. In its ORDER AFTER RECONSIDERATION, the Commission clarified that the reason it did not factor in such savings was because the Company had failed to document any such savings in the record. The Commission concluded that since the Company had failed to meet its burden of proving the value of the alleged energy cost savings, no offset was possible.[10]

Using the Department's new proposed method, then, $933,397 will be disallowed.[11] The new method is adopted for good cause. The new method takes into account the benefit of energy

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[10] In the Matter of the Application of Interstate Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota, Docket No. E-001/GR-91-605, ORDER AFTER RECONSIDERATION (October 19, 1992)at page 9.

[11] To illustrate the significant difference that this new valuation method makes, for the same amount of disallowed capacity (100 MW) the dollar amount disallowed in the last rate case was $1,958,117.

savings experienced due to the purchases. As such, it is a more appropriate way to calculate the ultimate costs involved.

Finally, the Commission agrees with the Department that Interstate's test year "other" operating revenues should be decreased by $125,487 to account for the below cost sale of capacity back to UPA. In denying Interstate recovery of the costs associated with 100 MW, the Commission is treating that amount as excess. Consistent with that treatment, revenue from the resale of that amount (or any portion thereof) should likewise be excluded from test year revenue.

XVIII. RATE OF RETURN ISSUES: SETTLED AND CONTESTED

A. Introduction

The overall rate of return represents the percentage the utility is authorized to earn on its Minnesota jurisdictional rate base. The overall rate of return is determined by the capital structure, which is the relative mix of debt and equity financing most of the rate base, and the costs of these sources of capital. The Commission will first address the capital structure, then the costs of debt and preferred stock and the cost of equity. Finally, the Commission will put these factors together to derive the authorized overall rate of return on rate base.

B. Capital Structure and Cost of Non-Common Equity Capital

1. Positions of the Parties and the ALJ

The parties and the ALJ agreed it was appropriate to use the following capital structure, which represents Interstate's financial position at the end of 1994. They also agreed to the cost rates shown for long-term debt, short-term debt, and preferred and preference stock. These costs are readily ascertained from a review of the Company's books.

Type of Capital	Amount (Thousands)	Percent	Cost	Weighted Cost
Long-term debt	$206,175	43.972%	7.752%	3.409%
Short-term debt	35,600	7.593%	6.070%	0.461%
Preferred & Preference Stock	34,597	7.379%	7.225%	0.533%
Common Equity	192,505	41.057%		
TOTAL	**$468,877**	**100.000%**		

2. Commission Findings and Conclusions

The Commission agrees with the ALJ that "Interstate's proposed capital structure is reasonable and balances the competing interests of investors and consumers. Interstate's capital structure falls within the range of comparable companies in 1994." The Commission concludes that Interstate's proposed capital structure, cost of debt and cost of preferred and preference stock should be adopted for this case.

C. Cost of Common Equity

1. Legal Guidelines for Commission Decision-Making

In reaching a decision on the appropriate cost of common equity, the Commission, as an administrative agency, must act both within the scope of its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide these general guidelines for Commission rate of return decisions:

a. the allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties;

b. the return should be sufficient to enable the utility to maintain its financial integrity; and

c. the return should be sufficient to attract new capital on reasonable terms.

See Bluefield Water Works and Improvement Co. v. P.S.C., 262 U.S. 679 (1923), and FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

No particular method or approach for determining rate of return was mandated by those cases, but the necessity of a fair and reasonable rate of return was clearly stated:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. Bluefield Water Works, 262 U.S. at 690.

The Minnesota Supreme Court has also provided some legal guidelines for Commission decision-making. In Minnesota Power & Light Company v. Minnesota Public Service Commission, 302 N.W.2d 5 (1980), the Court said:

> ...The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function; and (2) the allocation of rates among classes of utility customers, which is a quasi-legislative function.
>
> ...we now hold that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.
>
> 302 N.W.2d at 9.

In conducting its evaluation of the Commission's decision, the Court explained:

> ...A reviewing court cannot intelligently pass judgment on the PSC's determination

> unless it knows the factual basis underlying the PSC's determination. Judicial deference to the agency's expertise is not a substitute for an analysis which enables the court to understand the PSC's ruling. Henceforth, we deem it necessary that the PSC set forth factual support for its conclusion. The PSC must state the facts it relies on with a reasonable degree of specificity to provide an adequate basis for judicial review. We do not require great detail but too little will not suffice.
>
> 302 N.W.2d at 12.

The Commission will review the testimony of each of the parties on rate of return on common equity. The Commission will also review the recommendations of the ALJ. Finally, the Commission will draw its conclusions from the parties' testimony and determine the proper rate of return.

2. Summary of the Parties' Positions

a. Interstate

Interstate presented the testimony of Mr. Robert S. Jackson, a retired Senior Vice President of Stone and Webster Management Consultants, Inc. Mr. Jackson's recommendation of 11.75% was the result of averaging the results of five different studies.

The first study looked at the earned and projected rates of return for Interstate and a group of eight comparison electric companies, during the periods 1990 to 1994 and 1997 to 1999 (in rebuttal, Mr. Jackson looked at the years 1998-2000). For the group, the average historical return was 11.6%; for Interstate it was 10.7%. *Value Line* estimated the average return for the group at 11.9% for the projected period; for Interstate, it estimated 12.0%. Mr. Jackson noted that the average of the historical and projected returns for the group was 11.77%.

The second study, which was updated during rebuttal, was an average of discounted cash flow (DCF) quarterly market value and book value results. Mr. Jackson used historic and estimated future growth rates in per-share dividends and estimated future growth rates in per-share earnings. The yield component of the DCF formula resulted from the average of the high and low market prices during a three-month period, applied to the next four quarter's of expected dividends. For the group of companies studied, the updated result was a return on equity of 9.67%. For Interstate, the result was 9.87%. Mr. Jackson argued that these results do not represent the fair rate of return on Interstate's book value in this case, because the market price of the stocks for the comparison group and Interstate has been considerably above the book value for several years. Mr. Jackson therefore made a separate study, in which he adjusted the market value DCF result for the market-to-book ratio. This study showed an average required rate of return on equity of 14.80% for the group, and 12.06% for Interstate. Mr. Jackson averaged the results together for his DCF study, coming up with an average of 12.24% for the group and 10.96% for Interstate.

The third study, also updated, was a payout ratio test. Here, the group average was 12.29%; the result for Interstate was 13.78%.

Mr. Jackson's fourth study, updated in rebuttal, was a capital asset pricing model (CAPM) risk premium analysis. This study resulted in a cost of equity estimation of 11.56%.

The fifth study, which was updated, was a study of returns allowed for electric utilities, yielding a required return of 11.63%.

b. The Department

The Department presented the testimony of Dr. Luther Thompson, a Rate Analyst. Dr. Thompson performed a DCF study on Interstate, and one on a comparable group of electric distribution utilities.

For his Interstate study, Dr. Thompson reviewed dividend yields over four different recent periods: a 20-day yield (8.486%), a quarterly yield (8.620%), a one-year yield (8.886%) and a two-year annual yield (8.296%). The average of these yields was 8.572%. Dr. Thompson used a range of 8.50% to 8.70% as a reasonable estimate of the dividend yield for the current regulatory period, and chose 8.60% as the single best estimate of the current dividend yield.

Dr. Thompson looked at various growth rates which investors might be expecting, placing more emphasis on the more stable growth rates, such as those in book value and dividends. He examined particularly 5-and 10-year growth rates in book value, dividends, and earnings per share, as well as log linear growth rates. Based on these figures, he determined that investors would expect growth for Interstate in the range of 2%. Dr. Thompson reviewed the internal growth rate for 5- and 10-year periods, and Interstate's dividend payout ratio and earnings on common equity for the past ten years. He concluded that 2% was a reasonable growth expectation. The sum of the 8.60% dividend yield and the 2.0% growth rate led to an estimate of the cost of common equity for Interstate of 10.60%.

Dr. Thompson performed a DCF analysis also on a comparable group of electric distribution utilities. He determined that the average of the group's dividend yields ranged from 6.8% to 7.2%, and that the expected growth rate was 4.0%. Using 7.0% for the current dividend yield, he determined a cost of equity of 11.0% for the group.

Dr. Thompson recommended 11.00% for this case since the return for the comparable group of electric companies is the best estimate of the cost of common equity for Interstate's electric operations.

c. Mr. Ericsson

At the Albert Lea public hearing, Mr. Lester Ericsson, on behalf of the Minnesota Utility Investors (MUI), provided information on an average of recent rate decisions around the United States which he said supported a return on equity of 11.99%. Mr. Ericsson testified as a member of the public, and his testimony was not subject to cross-examination by any party.

3. The ALJ

The ALJ recommended that the Commission adopt Dr. Thompson's analysis.

He found that translating Interstate's risk into a just and reasonable return on equity requires an analysis which incorporates both its current yield and expected growth as well as an analysis of companies whose risk is comparable to that of Interstate. The ALJ noted that, while no one method of analysis is necessarily required, the discounted cash flow (DCF) method is generally considered to be the most basic and fair approach for regulatory purposes. He said it produces reasonable, consistent and fair estimates of the cost of common equity. He said the DCF model is basic to modern financial theory and provides objective information concerning the cost of common equity capital in the expected regulatory period.

The ALJ noted that the Minnesota Commission has consistently utilized the DCF method in making its determinations of the appropriate rates of return for Minnesota utilities. He quoted the Commission's Order in Interstate's last electric rate case: "The DCF method is firmly grounded in modern financial theory, and has been recommended by the Department and the RUD-OAG in this proceeding and by this Commission in nearly every case decided since 1978." Findings of Fact, Conclusions of Law and Order, Interstate Power Co., Docket No. E-001/GR-91-605 (1992), pp. 34-35.

The ALJ found Mr. Jackson's approaches to be too questionable to use confidently as a basis for setting rates and therefore declined to adopt his recommended return on equity.

The ALJ found that Department witness Thompson's DCF analysis is sound and complete, based on valid regulatory principles, consistent with Commission precedent, and productive of a fair rate of return for Interstate. Therefore, he recommended that Dr. Thompson's recommended return on equity of 11 percent should be used in this case.

The ALJ noted that Mr. Ericsson's proposal was not subjected to the kind of scrutiny and analysis that faced the proposals of Mr. Jackson and Dr. Thompson, including the prefiling of testimony and cross-examination under oath. Because Mr. Ericsson's proposed return on equity was not based upon an analysis accepted in the past by the Commission, or that can be shown to be conceptually sound, the ALJ did not consider it in arriving at his recommendation.

4. Commission Findings and Conclusions

The Commission adopts the ALJ's recommendation.

As the ALJ noted, the Commission has previously rejected Mr. Jackson's analysis. That analysis has not changed substantially since Interstate's 1991 electric rate case, Docket No. E-001/GR-91-605, and the Commission continues to find it inappropriate for determining the required rate of return.[12] Of the five studies, only two - the DCF and the Risk Premium - have potential to reveal the cost of equity requirements the market imposes on companies with risk similar to that of Interstate. But, as presented here, those studies fail to do so.

Mr. Jackson's DCF method proceeds more or less along conventional lines until he determines to adjust the result for market-to-book ratios in excess of one. That adjustment removes the market orientation of the study. Further, as Dr. Thompson pointed out, the adjustment moves the result

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[12] The Commission recently rejected this analysis in In the Matter of Interstate Power Company, Docket No. G-001/GR-95-401.

out of any reasonable range. (The updated study, without the adjustment, resulted in a cost of equity for the comparable group of 9.67%. With the adjustment, the cost moved to 14.80%.)

The Risk Premium method also suffers from Mr. Jackson's application of it here. Mr. Jackson uses 30-year Treasury Bond rates as a proxy for the risk-free rate. But the long-term study he relies on for determination of the risk premium uses the yield on those same securities as the base for determining the risk premium faced by stockholders as opposed to bondholders. It is improper for the same security to be both the risk-free proxy and the representative bond rate.

Risk premium analyses also tend to be extremely volatile, with the result varying significantly when there is a relatively small difference in the time of the analysis. Such is the case here. In Mr. Jackson's initial testimony, his Risk Premium analysis yielded an average cost of equity for his group of 12.39%. On rebuttal, that had changed to 11.56% -- a drop of 83 basis points in just a few months.

As it has in the past, the Commission finds the standard DCF analysis to produce reasonable, consistent, and fair estimates of the cost of equity. Dr. Thompson's application of it here, as the ALJ found, produces a cost of equity estimate that is fair both to investors and ratepayers.

The Commission concludes that the cost of common equity for the Company is 11.00%.

D. Overall Cost of Capital

The Commission finds the overall cost of capital is 8.919%, calculated as follows:

Type of Capital	Amount (Thousands)	Percent	Cost	Weighted Cost
Long-term debt	$206,175	43.972%	7.752%	3.409%
Short-term debt	35,600	7.593%	6.070%	0.461%
Preferred & Preference Stock	34,597	7.379%	7.225%	0.533%
Common Equity	192,505	41.057%	11.000%	4.516%
TOTAL	**$468,877**	**100.000%**		**8.919%**

XIX. REMAINING CONTESTED RATE DESIGN ISSUES

A. Seasonal Declining Block Rates

The Company proposed to offer declining block rates during the off-peak season to residential and single phase farm customers with substantially higher than average usage. All customers in both classes would pay flat rates for usage up to approximately 1.5 times the average. Usage exceeding that amount would be billed at reduced rates, to reflect the fact that these customers had already contributed their share to the fixed costs of the system.

During peak months, however, all customers would pay the same flat, per-unit rate, regardless of usage, to further conservation goals and defer the need for new capacity.

1. The Company's Position

The Company proposed seasonal block rates to align rates more closely with costs and to reward and encourage efficient use of its system. The Company argued that current rates over-recover fixed costs from high use customers and under-recover them from low use customers. Declining block rates are intended to reduce over-recovery from high use customers, promoting intraclass equity.

The Company also argued that rates should reflect the efficiency benefits high load factor customers bring to the system and all other customers. The more units sold during non-peak periods, the lower the per-unit cost of maintaining the plant and equipment necessary to meet peak. Lower overall costs translate into lower overall rates. Major contributions to system efficiency should be recognized and reinforced in rates.

2. The Department's Position

The Department opposed the Company's seasonal declining block rate proposal on the basis of three arguments. First, declining block rates conflict with conservation goals the Commission is obligated by statute to pursue. Second, declining block rates send inaccurate price signals, since the cost of producing electricity can vary with the season or time of day, but not with individual customers' cumulative consumption. Finally, the declining block rate structure at issue under-recovers costs in the tail block, since tail block rates do not include the costs of generation and transmission.

3. The Administrative Law Judge

The Administrative Law Judge recommended rejecting the Company's seasonal declining block rate proposal. He found that declining block rates send the inaccurate message that the unit cost of electricity decreases as consumption increases. He believed this message would reduce the incentive to conserve and could actually increase the use of electricity. He also found that the proposed tail block rates, by omitting generation and transmission costs, failed to recover the cost of the service.

4. Commission Action

The Commission will approve the Company's proposal in order to be fair to high usage customers, to align costs and rates more accurately, and to recognize in rates the benefits high load factors bring to the system as a whole. While the Commission's commitment to conservation remains as firm as ever, conservation goals can be served in this case without sacrificing the fairness and efficiency inherent in the Company's proposal.

It is undisputed that the flat rates currently paid by high use residential and single phase farm customers over-recover fixed costs, both in absolute terms and in comparison with the fixed costs recovered from average and low use customers. It is also undisputed that high use customers contribute more to keeping system costs low and rates affordable than average and low use customers. The issue is whether recognizing the cost benefits of higher consumption in rates is so at odds with the state's commitment to conservation that it must be rejected, even in the limited form proposed by the Company. The Commission concludes that it is not.

First, it is important to keep in mind that declining block rates will not be in effect during peaking season, when additional usage could translate into a need for additional capacity. Avoiding the need for new capacity, and all the direct and indirect costs new capacity imposes, is one of the primary goals of conservation. That was the goal the Commission sought to advance when it rejected the Company's year-round declining block rate proposal in its last rate case.[13] That is not an issue here, where the Company proposes to charge flat rates during peak season, when additional usage could create a need for additional capacity.

Second, important as conservation is, it does not invariably trump other traditional ratemaking values, such as intra-class equity, affordability, and efficiency. The Legislature has directed the Commission to set rates to encourage conservation "to the maximum reasonable extent,"[14] not to the exclusion of all other policy goals.

Rejecting the Company's proposal would mean requiring households and farms with above-average electric service needs to pay a disproportionate share of the fixed costs of the system, despite their disproportionate contributions to system efficiency and the overall affordability of rates. The rationale for over-recovering fixed costs from these customers would be to avoid sending an anti-conservation signal.

While the Commission is always concerned about anti-conservation signals, it is equally concerned, especially when dealing with residential and farm customers, about affordable rates and equitable rate structures. Given the fact that the anti-conservation signal here is weak (each additional unit carries additional cost; overall costs are covered; rates are higher during peak

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[13] In the Matter of the Application of Interstate Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket No. E-001/GR-91-605, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (June 13, 1992) pp. 62-63.

[14] Minn. Stat. § 216B.03 (1994).

season), the Commission concludes conservation concerns are outweighed by the demands of affordability and equity.

Finally, the Commission notes that the Department's and the ALJ's concern about tail block usage arguably being priced below cost is based upon examining tail block rates on a stand alone basis. These rates are not available on a stand alone basis, however. They are only available once a customer's usage exceeds 150% of the average, by which time generation and transmission costs have long since been fully recovered. (ALJ's Report, p. 38.)

Rate schedules are blunt instruments which seldom ensure full cost recovery for each increment of usage sold. Seasonal declining block rates are no exception. Since the total rate for declining block rate customers will always exceed cost, however, the Commission will not fine-tune the rate's components.

For the reasons set forth above, the Commission will approve the Company's seasonal declining block rate proposal.

B. Interruptible Rate Credit

The Company proposed to substitute an interruptible rate for its interruptible rider. The new rate was designed to reflect costs more accurately, to be more readily understandable, and to simplify billing and administration.

The new rate would be the same as the Large Power & Light rate, with a credit per kW of interruptible load based on generation costs at the Company's last-added peaking facility, a gas turbine facility near Lime Creek, Iowa.

1. The Company's Position

The Company believed the interruptible credit should reflect the cost savings resulting from interruptible load, which it saw as the costs of adding permanent peaking capacity to avoid interruption. Instead of conducting a study on the current costs of adding that capacity, the Company proposed to use as a proxy the generation costs at its Lime Creek facility, the last permanent peaking capacity it added to its system.

The Company noted that its interruptible rates were part of an overall Conservation Improvement Program (CIP) it was required by statute to administer under the direction of the Commissioner of the Department Public Service.[15] The Commissioner had approved the Company's CIP program using Lime Creek generation costs as the proxy for cost savings resulting from interruptible rates. The Company believed substituting a different measure of cost savings for ratemaking purposes could compromise the effectiveness of the CIP program and the reliability of the evaluation process at the end of the program.

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[15] Minn. Stat. § 216B.241 (1994).

2. The Department's Position

The Department opposed the Company's proposal to use Lime Creek generation costs to set the interruptible credit, claiming the credit should be based on the market value of interruptibility. Since there was no evidence of market value in the record, the Department proposed to use as a proxy the prices the Mid-Continent Area Power Pool (MAPP) would charge the Company for short term peaking capacity.

The Department argued that the costs of Lime Creek, having already been incurred, were unavoidable, and should not be used to set the interruptible credit. The costs that were actually being avoided by interruptible load were, in the Department's view, most likely the costs of purchasing peaking power from MAPP. The Department therefore supported using MAPP prices to set the interruptible credit.

3. The Administrative Law Judge

The Administrative Law Judge found that the key issue was what costs are being avoided when the Company asserts its rights under the interruptible tariff and interrupts customers. He found that those costs could not be Lime Creek costs, since at peak periods Lime Creek would be running at full capacity and full cost. Instead, those costs would be either the costs of building new peaking capacity or the costs of buying power from MAPP. He found it more likely that the Company would buy power from MAPP, and therefore recommended using MAPP prices to set the interruptible credit.

4. Commission Action

The Commission will base the interruptible credit on Lime Creek generation costs, because those are the only costs in the record which are a reasonable proxy for the costs of building or buying additional permanent peaking capacity.

The purpose of interruptible rates is to defer the need for permanent peaking capacity, not to defer the need for occasional short-term purchases of peaking capacity. MAPP purchases are by nature short-term.[16] The power pool does not exist to meet utilities' basic, structural capacity needs; it exists to help utilities meet short-term deficiencies. MAPP prices are not reliable indicators of the costs of adding permanent peaking capacity.

The Department and the ALJ are right that the costs of Lime Creek have already been incurred and are now unavoidable. The Company does not suggest, however, that Lime Creek's costs are the costs that will actually be avoided, just that they are a reasonable *proxy* for the costs that will be avoided, the costs of adding permanent peaking capacity.

No one has suggested, let alone offered evidence, that the costs of adding permanent peaking capacity have gone *down* since the Company added Lime Creek. The Commission, too, considers declining costs very unlikely and agrees with the Commissioner of Public Service's CIP finding

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[16] The MAPP price list on which the Department would base the interruptible credit applies to purchase terms of six months or less.

that the costs of Lime Creek generation are a suitable proxy for the cost of adding new permanent peaking capacity.

The Commission also shares the Company's concern that reducing the interruptible credit to the extent recommended by the Department could compromise, if not destroy, the effectiveness of its commercial/industrial CIP program. Interruptible rates, calculated using the costs of Lime Creek generation, were one of the linch pins of the Company's commercial/industrial CIP program. To dramatically increase those rates now[17] could damage the goodwill and customer confidence essential to the program's success.

The Company has testified its best guess is that implementing the Department's proposal would prompt nearly all interruptible customers to leave the system or switch to firm rates, effectively ending the CIP interruptible rate program. The Commission is unwilling to expose the Company's CIP program to this risk.

Besides endangering the program itself, the Department's proposal would at best complicate, and at worst compromise, final evaluation of its effectiveness. Changing conservation incentives in mid-course would make it difficult to gauge their effects on consumer behavior. Changing cost savings estimates in mid-course would make it difficult to compare projected and actual savings.

Finally, the Commission makes no finding on the appropriateness of developing market-based interruptible rates. While the concept is intriguing, the Commission recognizes the difficulties inherent in moving piecemeal to market-based rates, especially if the Company lacks the ability to adjust rates to the developing realities of the market. Presumably, the study of market-based rates agreed to by the parties will address these issues.

In any case, the Commission is convinced that for present purposes the Lime Creek generation costs are the only reasonable measure for the interruptible credit supported in the record.

XX. OVERALL FINANCIAL SUMMARIES

A. Rate Base Summary

Based on the above findings, the Commission concludes that the rate base for Interstate's test year is $73,095,000 as shown below:

[17] The Company's proposal -- $4.68 per kW per month -- is a fine-tuning of current credit levels. The Department's proposal -- $1.94 per kW per month -- is a substantial reduction in credit levels.

	(000s)
Utility Plant in Service	$143,759
Accumulated Depreciation and Amortization	(64,736)
Net Utility Plant in Service	79,023
Retirement Work in Progress and Net Acquisition Adjustment	423
Working Capital	2,577
One-half Rate Case Expenses	156
Customer Advances and Deposits	(253)
Accumulated Deferred Income Taxes	(8,831)
TOTAL RATE BASE	$73,095

B. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is $5,178,000 as shown below:

	(000s)
Operating Revenues:	
Retail Electric Revenues	$43,047
Other Revenues	1,247
Total Operating Revenues	44,294
Operating Expenses:	
Production	17,280
Transmission	1,039
Distribution	3,317
Customer Accounts and Services	1,786
Administrative and General	5,527
Depreciation and Amortization	5,211
Taxes Other Than Income	3,517
Federal and State Income Taxes	1,439
Total Operating Expenses	39,116
TOTAL OPERATING INCOME	$5,178

C. Gross Revenue Deficiency

Based on the Commission findings and conclusions, the Minnesota jurisdictional revenue deficiency for the test year is $2,287,000 as shown below:

	(000s)
Rate Base	$73,095
Rate of Return	8.919%
Required Operating Income	$6,519
Operating Income	5,178
Income Deficiency	$1,341
Revenue Conversion Factor	1.7056
Revenue Deficiency	$2,287

ORDER

1. Interstate is entitled to increase gross annual Minnesota jurisdictional revenues by $2,317,000 in order to produce total gross annual jurisdictional operating revenues of $46,611,000.

2. The Commission accepts and adopts the Settlement Agreement except for its treatment of CIP tracker amortization and customer charges.

3. The Commission modifies the Settlement Agreement as follows:

   a. the CIP tracker balance of $791,565 as of October 30, 1995 is to remain in the tracker account and accrue carrying charges on the monthly after-tax tracker balance the same as other CIP expenses are treated; and

   b. the customer charges (for all rate classes) are to remain at their current levels.

4. Any party who rejects the modification set forth above shall file a notice of rejection under Minn. Stat. § 216B.16, subd. 1a within ten days of the date of this Order.

5. Within 30 days of the date of this Order, Interstate shall file with the Commission for its review and approval, and serve on all parties to this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein, along with the proposed effective date.

6. Within 30 days of the date of this Order, the Company shall file with the Commission and serve on the parties, a revised base cost of fuel and supporting schedules incorporating the changes made herein. The Company shall also file its automatic adjustment establishing

the proper adjustment to be in effect at the time final rates become effective. The Department shall review these filings as it does other automatic adjustment filings.

7. Within 30 days of the date of this Order, the Company shall submit a compliance filing, in this matter, showing how it calculated its Conservation Improvement Program Cost Recovery Rate (CCRR).

8. The Company shall perform an analysis to determine the optimal interruptible credit based on market forces and to include this analysis in its next rate case.

9. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)

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