

Northern States Power Company
Case No. PU-12-813

Orders Approving use of 12CP and Identification of Prior Method Used

**March 24, 1988: NDPSC Findings of Fact, Conclusions of Law and Order
(Case PU-400-87-6)**

- In an electric rate increase application in NSP's North Dakota jurisdiction filed July 31, 1987, NSP proposed use of the 12CP method.
- The NDPSC found the peak and average method of allocation to be most reasonable. The rate increase request was denied.
- NSP's then current demand allocation method is identified as a weighted average of each jurisdiction's contribution to the Company's summer and winter peaks.
(See 3-24-88 Order bottom page 6/top page 7.)

December 13, 1988: Order Approving Settlement Offer (Case PU-400-87-6)

- A Rehearing of the March 24, 1988 NDPSC Order was conducted July 14, 1988 addressing, among other things, Jurisdictional Allocation.

On November 15, 1988, the NDPSC approved inclusion of the Minnesota Public Utilities Commission order in Case No. E002/GR-87-670, which supported use of 12CP as being consistent with the FERC adoption of the 12CP approach.
- On December 8, 1988, NSP presented a settlement offer asking the Commission to adopt the 12CP allocation method.
- The December 12, 1988 NDPSC Order approved the settlement, and thereby adopted the 12 CP Allocation method.
(Relevant orders attached.)

June 23, 1992: Findings of Fact, Conclusions of Law and Order (Case PUC-400-87-6)

- After several years of appeals and actions in District and Supreme Courts, the NDPSC's consultant prepared a June 10 1992 analysis of the settlement offer and evidence and recommended the proposed 12CP jurisdictional cost allocation method offered in the settlement based on 3 criteria:
 - “a. it reasonable reflects the incremental cost caused by each jurisdiction;
 - b. it is consistent among each of the company's jurisdictions; and
 - c. it is understandable, inexpensive to administer, and does not result in large swings in jurisdictional cost responsibility over time.”

(See 6-23-92 Order page 6)

October 31, 1991: NDPSC Findings of Fact, Conclusions of Law and Order (Case PU-400-91-112)

- In an electric rate case application for NSP's North Dakota jurisdiction filed March 8, 1991, the Commission again addressed jurisdictional demand allocation, approving a weighted 12CP method.
(see 10-31-91 Findings 4 through 17)

PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

Northern States Power Company)
Electric Rate Case)

CASE NO. 10,979
(PU-400-87-6)

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

DECIDED March 24, 1988

Appearances

Commissioners Dale V. Sandstrom, Bruce Hagen and Leo M. Reinbold.

Robert W. Senger, North Dakota Public Service Commission, State
Capitol, Bismarck, North Dakota 58505-0165, as Hearing
Examiner.

David M. Sparby and David A. Lawrence, Attorneys at Law,
Northern States Power Company, 414 Nicollet Mall,
Minneapolis, Minnesota 55401, appearing on behalf of
Northern States Power Company.

Myer R. Shark, Attorney at Law, 319 Fifth Street - Suite A,
P. O. Box 1616, Fargo, North Dakota 58107-1616, appearing
on behalf of Aggie Investments.

Lynn L. Schloesser, Commerce Counsel, North Dakota Public Service
Commission, State Capitol, Bismarck, North Dakota 58505.

PRELIMINARY STATEMENT

On July 31, 1987, Northern States Power Company ("NSP" or
"Company"), 414 Nicollet Mall, Minneapolis, Minnesota 55401,
applied to the Public Service Commission ("PSC" or
"Commission") to increase its rates for electric service to its
North Dakota customers. The filing consisted of two increase

Order in Case No. 10,979

Page 2

requests. The first request was for an interim increase of \$2,700,000 on an annualized basis to be effective January 1, 1988. The second request was for a final rate increase of \$6,075,000 or 8% on an annualized basis to be effective for sales from April 1, 1988.

NSP alleged the proposed increase was necessary to provide a fair return on its stockholders' investment in facilities used and useful in providing electric utility service to North Dakota customers. NSP claimed its stockholder investment had increased \$577 million due to the addition to its system of the Sherco 3 generating unit of which NSP owns 59%, or 472 megawatts.

On August 4, 1987, the Commission suspended NSP's rate filing pending staff investigation, formal hearing, and issuance of a final order.

On September 22, 23, and 24, 1987, the Commission held Public Input Hearings on NSP's rate case in Fargo, Grand Forks, and Minot.

On October 20, 1987, the Commission granted the intervention petition of Aggie Investments.

On November 3, 1987, the Commission denied the motion of Aggie Investments to change the location of scheduled technical hearings from Bismarck to Grand Forks, North Dakota.

On November 3, 1987, the Commission denied the interim increase request.

Order in Case No. 10,979

Page 3

On December 1, 1987, the Commission denied the motion of Aggie Investments to order NSP to testify on use of the "single annual peak method of allocation". The Commission stated that the information should be sought through data requests.

On December 7, 1987, the Commission denied Aggie Investment's Petition for Rehearing on Closing of Investigation in Commission Case No. 10,906 with respect to NSP's electric operations. In the order closing the investigation in Case No. 10,906, the Commission reserved Tax Reform Act issues with respect to NSP's electric operations for NSP's general electric rate hearing on January 5, 1987.

On December 7, 1987, the Commission denied Aggie Investment's Petition for Rehearing regarding Aggie Investment's motion for change of hearing location.

The Commission issued a Notice of Hearing on November 16, 1987. Hearings were held as scheduled on January 5 through 9, 1988, on the following issues:

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
3. What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

Order in Case No. 10,979

Page 4

4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are NSP's proposed rate schedules designed in such a manner that they result in a basis of change to its customers that is just and reasonable without discrimination?

All motions and objections not previously ruled upon in this proceeding have been considered and are hereby denied.

Having reviewed the record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

NSP is an investor-owned utility company engaged in providing retail electric service to North Dakota customers. The Company's headquarters are located in Minneapolis, Minnesota.

Test Year

The company's application is based upon a future test year ending December 31, 1988. Test year data and information in support of the application is based upon historical data. This approach is consistent with the Commission's past practice of setting rates for the future based upon an examination of a period when those rates will be in effect.

Order in Case No. 10,979

Page 5

We find the Company's use of a forecasted test period just and reasonable.

Jurisdictional Allocation

In this proceeding two allocation issues predominate: allocation of transmission system losses and demand costs.

NSP proposes a new means of allocating system-wide transmission losses as well as system-wide transmission plant. In prior electric rate proceedings NSP directly assigned some of its transmission facilities located in North Dakota to North Dakota. NSP also allocated to North Dakota only the losses actually incurred within the state to North Dakota. In the present case NSP recommends equalizing or proportionately allocating both the transmission plant cost as well as transmission system losses to North Dakota.

NSP has achieved the equalization of transmission plant costs by pooling the costs associated with all its transmission facilities. These costs then are allocated to the jurisdictions on the basis of the demand allocator. This method for allocating transmission facilities, like generation facilities, reflects the fact that the transmission system serves a system function of distributing power.

NSP has equalized transmission losses by determining demand and energy requirements for each jurisdiction at the high side of the distribution system and basing the allocators on these

determinations. The rationale for equalizing losses is that NSP's transmission network is built and operated to minimize system-wide costs.

Although such operation may minimize total costs, one physical consequence is that losses occur disproportionately in some geographic areas. A typical example of this results from energy sales to other utilities. Economy sales are made because NSP can make a profit for the entire system from such a transaction. The increased use of the transmission facilities for the economy transaction will cause electric line losses in the jurisdiction through which the energy passes. Under the present allocation method the benefits of the economy energy sale are not distributed back to customers on the basis of where losses are incurred.

Although NSP recovers all the cost of the losses, they are not distributed on the basis of how they are incurred unless losses are shared in the way proposed by NSP. Consequently, without the loss multiplier, economy sales or other transactions scheduled through a jurisdiction are not fully compensated for the losses incurred within that jurisdiction.

We find NSP's proposal to allocate transmission losses reasonable.

Through its witnesses Philip Zins and Steven Huso, NSP proposes a significant change in the method used to allocate demand-related costs to the North Dakota jurisdiction. NSP

Order in Case No. 10,979

Page 7

presently uses a demand allocation method that is a weighted average of each jurisdiction's contribution to the company's summer and winter peaks. In this proceeding, NSP proposes use of a method that uses an unweighted average of each jurisdiction's contribution to each of the twelve monthly peaks during the test year. The proposed method is called the average twelve-monthly coincident peak ("12CP") method.

NSP argues that the 12CP method is preferable to the weighted average of summer and winter peaks for several reasons. First the 12CP method accounts for each jurisdiction's contribution to peaks throughout the year as opposed to only two points. Second, NSP is not particularly strained in meeting demand at the occurrence of any particular peak because of the way maintenance is scheduled and other operational characteristics of the entire system. Third, while peak use is important for planning, use throughout the year is also important. Fourth, the 12CP method has been accepted by the Federal Energy Regulatory Commission ("FERC") for use between the NSP-Minnesota ("NSP-M") and NSP-Wisconsin ("NSP-W") companies. Fifth, the 12CP method is the method most likely to be accepted by all jurisdictions and general acceptance would avoid problems of over and under-recovery of revenues.

Intervenor, Aggie Investments, argues that the PSC should adopt the single coincident peak ("1CP") method of demand allocation. Aggie did not sponsor testimony to support this

Order in Case No. 10,979

Page 8

argument. Instead, Aggie argues that the PSC should adopt the LCP method based on record evidence of previous PSC decisions. However, Aggie also argues that this record supports an allocation method that gives more recognition to the system peak than NSP presently uses or proposes.

Commission staff witness Albert Clark examined NSP's proposed method as well as other demand allocation techniques including the LCP method, the average and excess method, and the peak and average method. Clark recommends the peak and average method.

The peak and average method uses the single annual peak as the measure of peak responsibility to allocate the system excess demand to the jurisdictions. The average demand of each jurisdiction is then added to the allocated excess demand to determine the jurisdictional demand allocation factors. Thus, this method represents a compromise between methods that merely recognize the seasonal peak or peaks and methods, such as 12CP, that give greater recognition to energy requirements of customers throughout the year.

We do not find NSP's testimony or arguments persuasive. The 12CP method was adopted by FERC for purposes of allocation between NSP-M and NSP-W. Comparison of annual load profiles of those companies may show very similar demand from season to season. However, comparison of jurisdictional demands for NSP-M alone does not show similar seasonal demand among its

jurisdictions. While the system peak occurs in summer, the North Dakota jurisdictional peak occurs in winter. The system summer peak is much higher than the system winter peak. NSP builds its system to meet the summer peak. Specifically, NSP builds its system to meet Mid-Continent Area Power Pool 15 percent reserve capacity requirements above the system peak. NSP witnesses testified that the system is built to meet both demand and energy requirements.

The Commission is not required to accept the FERC approved allocation method. The reasons for a l2CP method at the wholesale level do not apply to the state jurisdictions in this case. Re Utah Power & Light Co., 56 PUR4th 296, 301 (Wy. PSC 1985). The analyses conducted under the settlement agreement concluded "that the l2CP method was the most appropriate and should be adopted for charging system demand-related costs to the companies." Although the l2CP and other methods have been in use at the federal level for many years, NSP has not supported use of the l2CP method at the retail level until recently. We also note that the l2CP method for NSP was recently rejected by the Minnesota Public Utility Commission.

After narrowing the choices of allocation methods, NSP's final choice of a demand allocation method turned on the application of eight criteria. These criteria demonstrate a bias for the l2CP method. For example, criterion number seven is: "the method has reasonable administrative costs and can be applied within the time constraints necessary for operating the

Order in Case No. 10,979

Page 10

Interchange Agreement provisions." (Ex. 131, p.11). None of these criteria include examination of system planning and engineering. Yet system planning and operation should be the focus of such an inquiry. Re Virginia Electric and Power Company, 48 PUR4th 327, 334 (N.C. PSC 1982).

The 12CP method is most appropriate where "monthly peak loads are not substantially different from one another." Re Public Service Co. of Oklahoma, 19 PUR4th 190, 201 (F.P.C. 1977). The 12CP method dilutes the importance of NSP's high annual system peak which is crucial for NSP's planning for the installation and maintenance of adequate facilities. The 12CP method erroneously assumes that NSP retail jurisdictions require power supply facilities in proportion to their average monthly needs. Further, the 12CP method would assign excessive capacity costs to North Dakota ratepayers even though the Minnesota jurisdiction requires substantially more capacity per unit of average monthly demand.

The demand imposed by NSP retail customers is substantially greater during the summer months. As NSP witness Zins stated "the summer demand is relatively more important than the winter." (Tr. vol. 3, p.59). Because of the difference between summer and winter demand NSP's proposed rate design reflects class "differences in ... load patterns and contributions to summer and winter peaks." (Tr. vol. 3, p. 60). NSP's facilities have been designed to meet the

Order in Case No. 10,979

Page 11

summer system peak created in major part by the Minnesota jurisdictional customers and a large portion of NSP's capacity is excess during the rest of the year. Therefore, the 12CP method does not send the proper pricing signal to those who are responsible for system demand.

The "12CP method has the undesirable characteristic of understating cost responsibility for seasonal customers," such as the air-conditioning load of Minnesota jurisdictional customers. Re Idaho Power Co., 43 PUR4th 609, 627 (ID. PUC 1981). The 12CP method has the effect of ignoring seasonality by averaging away seasonal peaking behavior. Further, the 12CP method is appropriately rejected where another method "reasonably ... gives credit for the benefits of system diversity." Re Utah Power & Light Co., 56 PUR4th 296, 301 (WY. PSC 1983). Here the North Dakota jurisdiction is winter peaking while the NSP system is summer peaking. We find that the North Dakota jurisdictional customers should be given credit for diversifying the load on the NSP system.

The 12CP method should be rejected.

As an alternative to the 12CP method, the single CP method is allocation in the other extreme. Single CP allocation focuses on a single system peak alone. Exclusive focus on peak demand ignores the demand off peak customers who impose a cost on the system. Re Central Maine Power Co., 69 PUR4th 564, 577

Order in Case No. 10,979

Page 12

(Maine PUC 1985).

We reject the LCP method of demand allocation.

On the other hand, the peak and average method of allocation offers reasonable recognition of a strong peak which consistently occurs in the same season. Re Boston Edison Company, 53 PUR4th 349, 418 (Mass. DPU 1983). The peak and average method uses the single annual peak as the measure of peak responsibility to allocate system excess demand to the jurisdictions. Average demand of each jurisdiction is added to the allocated excess demand to get the jurisdictional demand allocation factor. Because NSP's system is designed, built and operated to meet peak and average demand there should be some recognition of average demand requirements. NSP equates average demand to the demand at the time of the eleven monthly peaks that are not the annual peak. The peak and average method averages every hour of demand throughout the year not just eleven one-hour monthly peaks.

We find the use of the peak and average method most reasonable. We find that the peak and average method best represents how the NSP system is planned and operated, and that this method most equitably recognizes cost responsibility among jurisdictions of both demand-related and energy-related costs. The jurisdictional demand allocation factor under the peak and average method when adjusted to reflect use of transmission loss multipliers is 5.73 percent.

Order in Case No. 10,979

Page 13

Finally, Clark proposed using a "weighted" customer allocation factor similar to that used in NSP's class cost of service study for customer accounting costs. NSP agreed with the concept of developing weighted customer allocation factors to reflect a different mix of customers by customer class between jurisdictions. In addition, NSP argued that the allocation factor for customer service and information should also be weighted for the jurisdictional study. The Commission agrees that both customer allocation factors should be weighted at the jurisdictional level.

Rate Base

Cash Working Capital

NSP performed a lead/lag study to determine a cash working allowance. A lead/lag analysis measures the amount of capital, on average, that must be provided by investors to the utility to pay those cash expenditures made during the period between the time service is rendered, and the revenues are received for that service. It is necessary to consider that portion of cash investment not supplied by investors and remove that amount from rate base. Cash not supplied by investors is supplied by vendors, employees, taxing authorities, and ratepayers. Investors are not entitled to earn a return on funds from these other sources. The measure of these other sources is the

Order in Case No. 10,979

Page 14

expense lag between the time the utility receives a good or service and the time it pays for that good or service.

In its lead/lag study, NSP proposes to recognize a 43.8 day delay between the recording of depreciation and deferred income tax expenses on its books and the receipt of payment from the customer of money to pay for the depreciation and deferred tax expenses. NSP argues that this delay should be recognized because (a) the company expends cash when it acquires a depreciable asset; b) the rate base is reduced at the time that depreciation is recorded; and c) even though depreciation is recorded, investors continue to be the source of the cash supporting the asset for 43.8 days until customer bills recognizing depreciation are in fact paid.

We find NSP's arguments unpersuasive. Depreciation and deferred tax expense are non-cash items. These items are book entries which do not involve any cash outlay or additional investment by stockholders. Since cash working capital is stockholder investment necessary to carry day-to-day operations of NSP, the depreciation expense and deferred income taxes must be removed from the lead/lag analysis. Finally, the depreciation and deferred tax reserves resulting from the accrual accounting method represent investment recovered from ratepayers and the portion of rate base on which NSP is no longer entitled to earn a return. Allowing these non-cash expenses in the lead/lag analysis imputes a return to a portion

Order in Case No. 10,979

Page 15

of the accumulated provision for depreciation and the accumulated deferred income taxes. We reject inclusion of these non-cash expenses in the lead/lag study.

On rebuttal, NSP witnesses agreed with Commission staff witness Clark's position on purchased power and fuel expense lag.

Commission staff witness Clark recommended exclusion of prepayments. NSP's prepaid expenses consist primarily of insurance premiums. Clark excluded prepayments on the basis that prepayments were disallowed in NSP's last North Dakota electric rate case 10,233.

In case 10,233 NSP relied upon the Federal Energy Regulatory Commission formula for determining its working capital requirement. Because the formula represented an estimate of total working capital requirements, the Commission did not believe it was appropriate to adjust the estimate for individual working capital requirements like prepayments. In the present case, however, the Company has relied on its lead/lag study to measure its working capital requirements. When a lead/lag study is used individual components of working capital are identified and measured. In preparing the lead/lag study measurement of cash working capital in the present case prepayments were not included. Prepayments are not a cash working capital requirement. Consequently, the value of prepayments to ratepayers was not reflected in NSP's proposed

Order in Case No. 10,979

Page 16

cash working capital requirement and must be separately considered to determine the proper level of working capital to be included in rate base. Since the asset clearly is used and useful to NSP's ratepayers, we find this asset should be included in rate base.

NSP, when it performs its lead/lag analysis, excludes from that analysis its costs associated with debt expense, preferred dividends, and common stock equity costs. The reason for this is that the costs are associated with NSP's individual capital components (debt, common stock equity, and preferred stock) and not operating expenses.

Despite NSP's method for determining cash working capital, and the reasons for it, Clark argues that funds used to pay preferred dividends and interest should be considered in NSP's lead/lag study.

We reject Clark's adjustment on this issue. The costs of debt, common stock equity, and preferred stock are properly determined in the rate of return analysis.

NSP used a revenue lag of 45.3 days in the lead/lag study. This includes two days for mail delivery of North Dakota customer payments to NSP. The Commission finds that a two-day lag is a function of the location of NSP's offices and that a one day lag is reasonable. North Dakota ratepayers need not be treated differently simply because of their geographic location. This adjustment results in a rate base reduction of \$171,400. Our decision here parallels our decision on transmission loss.

Order in Case No. 10,979

Page 17

In summary, we find NSP's 1988 forecast test year North Dakota rate base to be \$153,112,000.

NORTHERN STATES POWER COMPANY
 Jurisdictional Allocated Cost of Service Study
 Test Year 1988
 Rate Base Summary
 (000s)

Line No.	Item	Total Company	North Dakota
	<u>Plant in Service</u>		
1.	Production	\$3,161,435	\$181,088
2.	Transmission	497,715	27,045
3.	Distribution	1,061,759	67,541
4.	General	128,756	6,320
5.	Common	98,129	8,463
6.	TBT investment	17,711	1,054
7.	Total plant in service	<u>\$4,965,505</u>	<u>\$291,511</u>
	<u>Accum Prov for Deprec</u>		
8.	Production	\$1,260,996	\$72,230
9.	Transmission	139,585	7,563
10.	Distribution	332,722	20,117
11.	General	29,918	1,383
12.	Common	32,695	2,661
13.	Total accum prov for deprec	<u>\$1,795,916</u>	<u>\$103,954</u>
14.	Net plant in service	\$3,169,589	\$187,557
15.	Plant held for future use	\$ 395	\$ 7
16.	CWIP	\$ 40,088	\$ 2,007
	<u>Working Capital</u>		
17.	Unamort rate case exp	\$ 299	\$ 17
18.	Fuel inventory	51,802	3,316
19.	Materials and supplies	56,633	3,289
20.	Prepayments	4,815	285
21.	Cash working capital-lead/lag	-42,700	--1,827
22.	Delay in pay of deprec & deferred income taxes	0	0
23.	Total working capital	<u>\$ 70,849</u>	<u>\$ 5,080</u>
	<u>Accum Def Inc. Taxes</u>		
24.	Production	\$ 284,926	\$ 16,321
25.	Transmission	76,134	4,148
26.	Distribution	165,280	11,638
27.	General	22,895	1,043
28.	Common	19,696	1,466
29.	TBT related	109,514	6,926
30.	Total accum def inc taxes	<u>\$ 678,455</u>	<u>\$ 41,540</u>
31.	Total Rate Base	\$2,602,466	\$153,112

Expenses

Depreciation and Decommissioning

NSP proposes two significant changes since its last electric rate filing before this Commission. The first change is to the depreciable remaining lives assigned to certain generating facilities. The second change is to the depreciation expense required to fund the decommissioning of the Company's two nuclear generating facilities. The most significant change is made to the depreciable remaining lives assigned to NSP's two nuclear generating facilities. For the Monticello plant, NSP extends the remaining depreciation period from January, 2002 to June, 2007. For the two units at Prairie Island, the previous termination dates for depreciation (January, 2004 for unit 1 and January, 2005 for unit 2) are moved to June, 2008.

In addition to extending the plant lives, NSP has performed a major study to update the estimated future cost of decommissioning the Company's two nuclear generating facilities. The previous study that NSP had been using to establish decommissioning costs was based on 1979 information and used a generic decommissioning study scaled to NSP's generating facilities. The new study indicates that the estimated cost to decommission NSP's nuclear facilities in 1986 dollars are \$186.8 million for Monticello and \$311.6 million

for the two units at Prairie Island. The effect of the new study is to increase the 1979 total corporate decommissioning expense by \$11.9 million. We agree that the decommissioning expense has increased.

Labor

Commission staff witness Clark made an adjustment to labor. On rebuttal NSP adjusted its labor expense downward below Clark's adjustment to reflect projected results of its early retirement program. We adopt NSP's adjustment to labor.

Tax Reform Act of 1986

Intervenor Aggie Investments argues that the effect of changes in the federal corporate income tax rate should be passed through to ratepayers. This proceeding includes consideration of the reduced federal income tax rate for the test year. Tax savings realized in 1987 offset increased expenses incurred in 1987.

Rate Case Expense

NSP proposed that an estimated rate case expense of \$33,000 be amortized over two years and that the average first year balance of the unamortized rate case expense of \$24,750 be included in rate base.

Order in Case No. 10,979

Page 20

Clark recommended a three year amortization period to reflect the expected time that rates proposed in this case will be effective. Clark also recommended that the unamortized balance of rate case expense be included in rate base at a three year levelized balance of \$16,500. We agree. A three year amortization period is more in step with reality. It has been six years since NSP's last electric rate case before this Commission, and a three year levelized balance of \$16,500 provides a better match over the three year amortization period.

Dues and Donations

Clark removed \$24,000 of donations included in NSP's test year revenue requirement. NSP proposed equal sharing of these costs between ratepayers and shareholders. Clark's adjustment is consistent with this Commission's position in previous cases. We do not believe those dues and donations should be passed through to ratepayers as they would become forced contributions over which the ratepayers would have no control.

Organization Dues and Expenses

Clark removed \$27,000 of organization dues and expenses that do not benefit NSP ratepayers. The Commission finds Clark's adjustments to the proposed organizational dues and expenses reasonable.

Rate of Return

NSP proposed an overall cost of capital of 10.19%. Commission witness Larry Dobesh proposed an overall cost of capital of 9.48%. The difference in these positions lies in the estimate of the required return on common equity. There is no dispute regarding capital structure.

NSP's witness Paul Pender used a discounted cash flow ("DCF") method to estimate the cost of common equity. He also performed an equity risk premium analysis. As a result of his analyses, he recommended a 12.81% cost of equity.

Dobesh also used the DCF method to estimate the cost of common equity. Dobesh recommended 11.24% cost of equity for NSP. Dobesh undertook several steps to estimate a fair return for NSP. These steps included:

1. A general description of recent trends in the capital markets.
2. A general description of recent trends in the financial performance of the industry.
3. A general description of recent trends in the financial performance of NSP.
4. A development of the appropriate criteria for a fair rate of return.
5. A determination of the component costs of debt preferred, and common equity for NSP.
6. A determination of the appropriate proportions of debt, preferred and common equity for NSP's capital structure.

7. A calculation of the weighted average cost of capital.

Based on Dobesh's testimony, trends in capital markets show rapid decline in inflation and interest rates. Capital costs are significantly lower today compared to 1981 when NSP last filed. For the industry, except for a handful of utilities recently involved in large nuclear construction projects, most electric and combination electric and gas utilities have successfully recovered from adverse financial conditions experienced in the late 1970's.

Several facts demonstrate the favorable financial health of NSP. NSP stocks purchased in 1976 and sold in 1986 would have had an average annual return of 17.15 percent. Recently NSP's return on equity has been good. In 1986 its return on equity was 15.25 percent, compared to 13.81 percent for the industry. Likewise, NSP's market to book ratio has soared from .79 in 1980 to 1.51 in 1986. The industry market to book ratio was 1.39 in 1986. From Friday, October 16 to Monday October 19, 1987, the price of NSP stock fell 12.5 percent. The overall market fell 22.6 percent, and the Dow Public Utility Average fell 15.3 percent. Obviously, investor confidence was relatively higher in the financial strength of NSP. By October 27, 1987, the price of NSP common equity had regained all it had lost on October 19.

The criteria for a fair rate of return are set forth in Bluefield (1923) and Hope (1944). These criteria are frequently

referred to as the comparable earnings and capital attraction standards. Following these standards, both Dobesh and Pender agree that the cost of long term debt is 8.45 percent, for short term debt is 6.89 percent, and for preferred stock is 6.74 percent. Dobesh and Pender also agree on capital ratios: long-term debt, 40.96 percent; short-term debt, 2.73 percent; preferred stock, 11.06 percent; and common equity, 45.25 percent. Dobesh and Pender differ in the estimated cost of equity capital.

Dobesh and Pender differ in the selection of comparable risk utilities for use under the DCF analysis. Dobesh selected sample utilities based on bond ratings. Pender selected sample utilities based on bond ratings and common stock. However, among the measures of risk, bond ratings are widely used in the investment community to assess overall risk of a utility. Bond ratings have the advantage of being established by reasonably objective organizations.

To determine market cost of equity, both yield and growth must be determined. Dobesh's sample utilities showed a combined yield and growth rate of 10.77 percent, while Pender's was in excess of 12.5 percent. Using the DCF method and data, Pender found NSP's historic cost of equity to be 13.77 percent. On the other hand, NSP's recent historical return on equity was 17.07% in 1983; 16.35% in 1984; 15.58% in 1985; and 15.25% in 1986.

Order in Case No. 10,979

Page 24

Because NSP's market-to-book ratio is well above one, regulators can expect to continue to decrease the ROE for NSP. Thus, a reasonable expectation for NSP's future return on equity would be 14.50 percent, resulting in an expected growth rate of 5.08%. Combining NSP's dividend yield of 6.12% and expected growth rate of 5.08% results in an estimated cost of equity of 11.20%.

We find Dobesh's approach more realistic and rely on his DCF analysis and adopt his recommendation. We note also that Pender employs a risk premium analysis which we have previously rejected and again reject here.

Operating Income Statement

NSP and Commission witnesses agreed on usage forecasts or projected sales of electricity for the test year.

With the adjustments adopted above, the Commission finds that a revenue reduction of \$427,000 should be made as follows:

NORTHERN STATES POWER COMPANY
 Jurisdictional Allocated Cost of Service Study
 Test Year 1988
 Income Statement and Rate of Return Earned
 (000s)

Line No.	Item	Total Company	North Dakota
Revenues			
1.	Sales of electricity	\$1,187,449	\$ 76,391
	Other operating	170,516	10,225
	Gross earnings tax	17,914	1,137
4.	Total operating revenues	\$1,375,879	\$87,753
Operating expenses			
Operation & maintenance			
5.	Production	\$ 582,580	\$ 35,967
6.	Transmission	27,626	1,549
7.	Distribution	79,045	4,438
8.	Customer accounting	31,132	2,076
9.	Sales	1,034	35
10.	Customer service & information	8,474	1,351
11.	Administrative & general	85,760	5,768
12.	Subtotal - Oper. & Maint.	815,651	51,183
13.	Depreciation expense	169,061	9,936
14.	Property tax expense	101,981	5,140
15.	Gross earnings tax expense	18,203	1,159
16.	TBT miscellaneous expense	-2,594	-164
Income taxes			
17.	Provision for deferred taxes	21,225	982
18.	Current income tax expense	53,830	5,244
19.	Investment tax credit - net	-8,355	-504
20.	Subtotal - income taxes	66,700	5,722
21.	Total operating expenses	\$1,169,002	\$72,975
22.	Net operating income	\$206,877	\$14,777
23.	Total rate base	\$2,602,466	\$153,112
24.	Rate of return earned	7.95%	9.65%
25.	Required rate of return		9.48%
26.	Required net income adjustment		\$-262
27.	Required revenue adjustment		\$-427

Rate Design

NSP performed class cost of service studies. However, reasonable rate design requires the Commission to base its decision not only on cost of service studies, but also on other quantifiable and unquantifiable factors.

Based on a reduction in revenue requirement of \$427,000 we find that changes in rate design should be minimized. We find that new tariffs which use current rate design and produce an approximate across-the-board percentage reduction will minimize rate changes with the following guidelines for new tariffs.

NSP proposes that several customer classes be eventually combined with other customer classes because the customers have similar usage characteristics and, therefore, continuing to maintain specially tailored rate schedules is not justified. We agree that the classes should be combined and therefore the Company should begin a transition to combine municipal pumping customers and direct current customers with the general service classes and combine the peak interruptible class into the peak-controlled time of day service. The first step of the transition should move one-third of the way toward the goal.

The Company should combine the institution of higher education customer class and the general water heating service with either the general service classes or the residential service. A transition period is not required.

Order in Case No. 10,979

Page 27

NSP proposes to begin a \$2.00 customer charge to the energy controlled dual fuel service to partially reflect the fixed customer costs of \$5.08 per month. We agree that a customer charge should be introduced to this class of service and a \$2.00 charge is a moderate beginning.

The Company proposes to add a new off-season load rider to the general service class customers who have load requirements during times when the NSP system requirements are low or off-peak. We agree that this customer is beneficial to the NSP system and the rider and resulting rate should better reflect the cost of providing service.

The Company proposes a standby service rider to replace the existing standby and supplementary service rider. The new rider contains provisions resulting in rates which more accurately track costs. We agree with NSP's proposal which will more accurately recover costs.

NSP proposes to eliminate the option for a time-of-day (TOD) residential customer to make a one-time payment rather than make the monthly payment for the TOD meter. NSP also proposes to eliminate the option for residential underground customers to make a one-time payment rather than make the monthly underground charge. NSP alleges the carrying costs and maintenance costs for these items continue for the life of the facility and do not stop when the one-time payment is made. We agree.

Order in Case No. 10,979

Page 28

NSP proposes to increase the returned check charge from \$5 to \$10 to more accurately reflect the full cost. We agree.

NSP proposes to replace the maximum charge provision of the general service rate with the revised determination of demand provision capping the level of billing demand. The revised method of calculating the maximum demand charge for a general service customer will have a minimal rate impact on the customer but will result in a tariff that is easier to administer. The Commission agrees with the proposal.

NSP proposes to increase the size of the customers who may qualify for the peak controlled and peak controlled time-of-day tariffs by requiring that the customer controllable demand be 100 kw or greater. At this time, NSP has no customers using this rate that have a load lower than 100 kw. We therefore agree with the proposal.

Commission staff proposes an underground charge for small general service customers so that rate policy would be consistent between this class of customer and the residential customer. We believe the Company incurs costs of providing underground service to small general service customers that are likely equivalent to costs incurred for a residential customer. Therefore, we find that the small general service customers who have underground service should be identified so that an underground service charge can be incorporated in the tariff at the time of the next rate proceeding.

The Company proposes to introduce several other tariff changes. NSP proposes a rider to its general service rate which would allow NSP to reduce the price of its service to individual customers when necessary to meet competition from another energy source. The Company has a right and expects a reasonable return on its investment. We find that such customers not providing that level of return is a burden to other ratepayers unless there is excess capacity on the system. NSP has testified there is no excess capacity on its system and the Commission applauds the Company's efforts to keep excess capacity at a minimum. Therefore, we reject NSP's proposed rider to its general service rate.

The Company proposed two new classes of customer within the general service rate, general time-of-day rate, peak-controlled service rate, standby service rider, and off-season load rider. The two new customer classes are the transmission-transformed and the transmission customer. The Company has testified that there are no customers of this type in North Dakota.

Since the results of the embedded class cost of service study and the marginal class cost of service study did not provide conclusive evidence concerning the magnitude of demand voltage and energy voltage discounts for these two classes of customers, and since none of these customers presently exist, the Commission finds that the NSP tariff should exclude these

classes at this time. Further, NSP's definition of transmission-transformed customers may be discriminatory.

Commission staff proposed the portion of street and area lighting rates involving rental and maintenance of lighting fixtures be deregulated. The Commission expresses no opinion at this time on the scope of its regulatory authority over lighting fixture services.

Integrated Resource Planning

We expect NSP to continue to use least cost planning to supply energy at the lowest possible cost. In this regard, we define "least cost planning" or "integrated resource planning" for an electric utility to be the consideration of both supply and demand-side options in selecting the least cost method of meeting the energy and demand needs of customers. The demand-side and supply-side resources considered will be evaluated in terms of benefit/cost criteria. A resource will be considered as passing the primary test for cost effectiveness if it can satisfy load at a lower cost to the utility than any other resource. Once this test is satisfied, the resource will be further considered in terms of other impacts: rate impacts, environmental impacts, load profile impacts and other pertinent impacts. If these other impacts do not negatively outweigh a favorable benefit/cost ratio for the resource, the resource should be adopted.

We find that NSP's conservation program is quite good--it is based on the appropriate methods and the scope of its program addresses the major uses of electricity, although generally we adopt the changes recommended by Commission staff witness Dobesh to NSP's conservation efforts.

First, in the residential area, NSP currently offers rebates for purchases of efficient appliances; energy efficiency audits for structures; a Good Cents Program to encourage builders (although there are no cash incentives) to achieve high thermal efficiency for both single and multi-family all-electric dwellings; and a loan program (up to \$750 @ 12%) for ceiling insulation in existing residential structures.

In evaluating conservation resources, NSP should increase the benefits of conservation by 10 percent. This would reflect the environmental benefits and risk reduction benefits of conservation. If this adjustment makes certain conservation measures cost effective that were not cost effective before the adjustment, those measures should be implemented as soon as possible. With this 10 percent adjustment, NSP should reevaluate its conservation rebates to determine if high rebates would encourage residential customers to acquire more cost effective conservation. If so, rebate schedules should be revised as soon as possible.

Order in Case No. 10,979

Page 32

The Company's Good Cents program is achieving greater than 90 percent penetration rate. This is excellent, but we believe NSP should do better. For instance, if it is cost effective to achieve a 100 percent penetration, then NSP should offer cash incentives to builders. "Leaky" structures will go on wasting energy for years if they are not insulated at the time of construction. Many retrofit programs will simply not be cost effective after construction. It is important for NSP to capture these "lost opportunity resources" while it can. Lost opportunity resources are those cost effective conservation measures that, if not undertaken today, will be lost forever. Thus, NSP is directed to file, within six months, a cash incentive or other program whose goal would be to increase penetration of Good Cents dwellings. In addition, we are concerned that NSP's Good Cents standards may be set too low given the high percentage that meet those standards. NSP should examine the cost effectiveness of higher Good Cents standards and, if cost effective, raise its existing standards.

We believe NSP could reduce its administrative expenses and revive its Attic Reinsulation program by replacing the current loan program with a cash rebate program. Loan programs are burdensome. They involve tracking an account over the life of the loan and having persons involved in the collection of bad debts. In addition, NSP's interest rate of 12 percent is certainly not generous enough to encourage widespread

participation. NSP is directed to submit to this Commission, within six months, a replacement for its Attic Reinsulation loan program. The replacement could be a cash incentive program with the incentive determined from the cost effectiveness approach recommended by Dobesh.

NSP does not offer special conservation programs for low-income families, although its own research indicates those families are often left out of conservation investments. To prevent conservation programs from adversely affecting the poor, NSP is directed to seek ways to increase their participation in conservation. Rather than advocate a particular path at this time for helping the low income, we direct NSP to study the alternatives and present a proposal within one year.

The second area of conservation programs is for commercial and industrial customers. Presently, NSP offers rebates for efficiency improvements in lighting, motors, and cooling. In addition, NSP offers energy efficiency audits to its business customers.

For these customer classes, NSP is directed to re-evaluate the level of its rebates in light of the 10 percent conservation credit recommended by Dobesh. In addition, if cost effective, NSP should have a Good Cents type program available for builders of commercial and industrial structures that are heated or cooled with electricity.

Order in Case No. 10,979

Page 34

Although NSP is proceeding in the proper direction regarding conservation, a concerted and time-consuming effort must be made to understand the scope of NSP's conservation efforts. To make the Company's conservation efforts easier to understand and evaluate in the future, Dobesh recommended that NSP's tariffs for conservation measures must contain more information. Conservation tariffs should give a summary table of the cost effective marginal or avoided costs for each type of conservation program. Those "conservation rates" would be shown by season and, if applicable, by time of day and for kwh and kw. At a minimum, conservation tariffs should be filed yearly. If there is a significant change in the conservation rates or if new programs are implemented, a conservation tariff could be revised between the yearly filings. Workpapers that show how rebate levels were determined from conservation rates should also be filed with conservation tariffs. We adopt Dobesh's recommendations.

By requiring yearly filings with an explicit showing of cost effectiveness levels, the Company will be constantly aware of this Commission's intent that all cost effective conservation programs be implemented.

To evaluate the need for conservation and the performance of the Company's current programs, its presently filed yearly report on conservation and load management needs improvement. First, the initial section of the report should contain a

Order in Case No. 10,979

Page 35

table(s) and graphs which show the historical and forecast growth (three scenarios for 20 years) of energy and peak demands in relation to committed and planned capacity. Dobesh's Schedules 32 and 12 in this proceeding are a guide. The current report filed by NSP contains nothing on demand growth. Moreover, NSP's table titled "Supply Plan" in the April 1987 conservation/load management report actually does not show planned supply but only committed supply. In all, the current report leaves the reader blind on the force behind new conservation or generation--load growth--and does not reveal the relative importance NSP is placing on demand-side versus supply-side options in meeting that growth. We direct NSP to make these changes in its report on conservation.

Second, the present report lists the number of participants in a program. For example, the July 1, 1987 report shows 187 single family homes in North Dakota have been certified as Good Cents homes from the start of the program to April 30, 1987. However, we do not know if this was 1 percent or 100 percent of all newly constructed, all electric homes in the state. We also don't know how much energy and demand was saved by those 187 homes and whether the Good Cents program was cost effective. We direct NSP to make these changes.

NSP's conservation and load management reports filed with this Commission must show, on a North Dakota and System basis, estimated program penetration among eligible customers;

estimated energy or demand savings (or shifting); and estimated cost effectiveness of the individual programs. We realize North Dakota is a small share of NSP's overall operations and want this report to be "cost effective". Thus, NSP may use estimates from Minnesota studies if applicable to North Dakota and some specific numbers may be omitted if too expensive to determine.

CONCLUSIONS OF LAW

1. The North Dakota Public Service Commission has jurisdiction of this proceeding.
2. The existing level of NSP's rates is excessive.
3. NSP is entitled to a revenue level adequate to allow it to earn a just and reasonable rate of return on its North Dakota rate base.
4. A \$427,000 reduction in revenue requirement will allow NSP to earn a just and reasonable rate of return on its North Dakota electric rate base.

From the foregoing Findings of Fact and Conclusions of Law, the Commission issues the following:

ORDER

NSP's application for an increase in electric rates is denied.

Order in Case No. 10,979

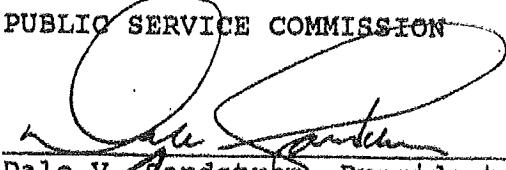
Page 37


NSP is ordered to file rates consistent with the findings set forth above that will reduce the revenue requirement by \$427,000.

Bismarck, North Dakota, March 24, 1988.

(S E A L)

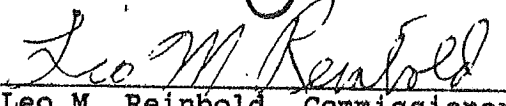
PUBLIC SERVICE COMMISSION


Dale V. Sandstrom, President


Bruce Hagen, Commissioner

ATTEST:


Secretary


Leo M. Reinbold, Commissioner

0111V