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September 16, 1998

BEFORE THE  
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company (Wisconsin) for  
Authority to Modify Rates for Retail Electric Service and Retail  
Natural Gas Service in Wisconsin 4220-UR-110

**FINDINGS OF FACT, CONCLUSIONS OF LAW,  
ORDER**

**Proceedings**

On November 14, 1997, Northern States Power Company-Wisconsin (NSPW or Applicant) filed an application with the Commission under ss. 196.03, 196.20 and 196.37, Stats., and ch. PSC 116, Wis. Adm. Code, for authority to increase its retail electric service rates in Wisconsin by \$12,692,000 or 4.3 percent and decrease its retail natural gas service rates in Wisconsin by \$1,708,000 or 1.9 percent. NSPW prefiled various exhibits and related testimony pertaining to financial and rate information with its application.

A prehearing conference was held on March 12, 1998, to identify the persons who would actively participate in the rate hearing as full parties; specify dates for filing testimony and exhibits; identify and designate issues; and consider other matters as would facilitate the hearing. A technical hearing was held in Madison on April 24, 1998.

The parties, for purposes of review under s. 227.53, Stats., are listed in Appendix A, attached hereto. Other persons who appeared are listed in the Commission's files.

A rate increase for retail electric utility operations in the amount of \$7,256,000 and a rate decrease for retail gas utility operations in the amount of \$1,936,000 is authorized for the test year ending December 31, 1998. This is a 2.5 percent increase for retail electric rates and a 2.2 percent decrease for retail gas rates.

## **FINDINGS OF FACT**

### **THE COMMISSION FINDS:**

#### **NSPW and Its Business**

NSPW is a public utility as defined in s. 196.01, Stats., operating as an electric and gas utility. NSPW is engaged in the production, transmission, distribution and sale of electrical energy to approximately 206,900 retail electric customers in northwestern Wisconsin; to approximately 9,400 retail electric customers in the western tip of the Upper Peninsula of Michigan; and 10 wholesale customers in the same areas. It is also engaged in the purchase, distribution, and sale of natural gas to approximately 70,300 customers in Wisconsin, and 4,800 in Michigan. The Michigan Public Service Commission regulates the retail sales of electricity and natural gas in that state.

NSPW is a wholly owned subsidiary of Northern States Power Company (NSP), whose principal office is located at 414 Nicollet Mall, Minneapolis, MN 55401.

#### **Estimated Results of Operations at Present Rates**

##### **Commission Staff Income Statement Adjustments**

NSPW and Commission staff presented testimony and exhibits concerning estimated costs of electric and natural gas operations for the 1998 test year. Opportunity was afforded to all parties to cross-examine all witnesses. There were a number of issues related to Commission staff's income statement adjustments. Unless otherwise stated, the Commission finds Commission staff's adjustments are reasonable.

Among the adjustments are those which reflect the Commission's established policies for NSPW regarding association dues and economic development expenses. Commission staff removed association dues expenditures for organizations deemed not to have a "direct and substantial benefit to ratepayers." Commission staff adjusted economic development expenditures (including advertising expenditures) to the 1996 actual level, plus inflation to a 1998 test year level. This is the policy approved by the Commission in the order in docket 4220-UR-105.

##### **Deferral of Network Transmission Service Costs**

Network Transmission Service (NTS) costs are the result of the Federal Energy Regulatory Commission (FERC) Order 888, which requires transmission-owning utilities to offer transmission services to entities wishing to use their transmission system. NTS allows the transmission service customer to fully integrate load and resources on an instantaneous basis. Network facilities owned by a transmission customer become part of the network cost. All customers of the network system share in the costs of the network based on their load ratio share. Under this arrangement, Northern States Power Company-Minnesota (NSPM) (the parent

company of NSPW) is required to pay transmission costs to certain of these customers if the customer's investment in integrated transmission facilities per unit of load is higher than that of NSPM. NSPW, in turn, is billed by NSPM for its share of those costs as determined by the interchange agreement.

NSPW did not include the impact of NTS costs in its 1997 test year rate case (docket 4220-UR-109) since such costs were not identified until late in the rate case process. Instead, the company requested permission to defer such costs on May 23, 1997. On July 17, 1997, the Commission authorized the company to defer NTS costs beginning May 24, 1997. During the audit in the present case, the company indicated that NSPM was in the process of negotiating with its transmission customers to adjust amounts already paid by NSPM for NTS costs as well as establishing new rates for future service. The company further indicated that there is a wide range of possible outcomes from the negotiations and that it hoped to have firm numbers by the time of the rate case hearing. At the time of the hearing, negotiations had not been completed by NSPM.

The Commission finds it is reasonable to include \$4,275,519 of NTS costs in revenue requirement in this docket and to continue to defer any differences. Inclusion of NTS costs in revenue requirement in this proceeding will allow NSPW to collect such costs from the ratepayers who will benefit from the expenditures as opposed to deferring all costs until a final settlement is reached. NSPW will inform the Commission when NSPM has reached final settlements with all parties. The remaining amount deferred will be addressed in the next rate case.

### **Advertising**

It has been the Commission's policy to remove costs of advertising which contain more than an incidental amount of goodwill. Such advertisements are referred to as "mixed" advertisements. Section PSC 12.04(3), Wis. Adm. Code states that mixed advertisements may not be charged to ratepayers. Commission staff had proposed to remove advertising costs for a significant number of advertisements due to the goodwill element present in those advertisements. Commission staff cited the advertisements in question for presence of self-laudatory statements and for lack of relevant information. The company argued that the goodwill element contained in the advertisements in dispute did not constitute "more than an incidental amount of goodwill." The advertisements in dispute were conservation advertisements. Since conservation expenditures are escrowed, these costs would be removed from the escrow.

The Commission reviewed each of the advertisements in dispute and found it reasonable to remove advertisements that included information on the proposed merger between NSP and Wisconsin Energy Corporation and advertisements it found to contain more than an incidental amount of goodwill. The Commission did not find it reasonable to remove any advertisements due solely to the lack of a telephone number. Of the advertisements in dispute, the Commission allowed the advertisements contained on pages 3, 4, 5, 7, 9, 10, and 11 of Exhibit 12, Schedule 2. Consequently, the Commission finds it reasonable to reduce the amount charged to the

conservation escrow by \$301,501. This adjustment will be reflected in the calculation of the amortization of underspent conservation.

### **Demand-Side Management (DSM)/Conservation Expenditures**

In the order in docket 4220-UR-108, the Commission approved NSPW's proposal to eliminate capitalization of DSM/conservation incentives. Consequently, all conservation expenditures from January 1, 1996, going forward have been (and will be) expensed. In addition to these expenses, the amortization expense associated with conservation expenditures has been capitalized only through the end of 1995.

NSPW had requested permission to remove expenditures for "DSM advice" from the escrow and place them in the regular operations and maintenance budget. This request was based on NSPW's assumption that its customers will expect them to continue to provide such advice regardless of decisions made in the future with respect to the types of conservation activities utilities will be allowed to perform in a deregulated environment. The Commission finds that it is not reasonable to allow NSPW to segregate costs from the conservation escrow for "DSM advice" at this time, given that utilities receive DSM goal "credits" for efforts to advise and educate customers. NSPW should continue to monitor such costs so as to allow for a more accurate segregation of costs in the future—if and when that becomes necessary.

Appropriate Wisconsin retail electric DSM/conservation expenditures for the 1998 test year which reflect the Commission's accounting policies are as follows: the level of escrowed DSM/conservation expense included in the 1998 test year revenue requirement is \$2,720,374. This amount reflects budgeted expenditures for the test year of \$4,380,600, less amortization of prior years' underspending of \$1,660,226, or \$138,352 monthly. Amortization of already-capitalized electric DSM/conservation incentives (net of deferred income taxes) included in the test year revenue requirement is \$871,226.

Appropriate Wisconsin retail gas DSM/conservation expenditures for the 1998 test year which reflect the accounting policies are as follows: the level of escrowed DSM/conservation expense included in the 1998 test year revenue requirement is \$744,769. This amount reflects budgeted expenditures for the test year of \$1,628,017, plus amortization of prior years' underspending of \$883,248, or \$73,604 monthly. Amortization of already-capitalized gas DSM/conservation incentives (net of deferred income taxes) included in the test year revenue requirement is \$181,726.

### **Electric Monitored Fuel Rules Costs**

The Commission finds that a reasonable estimated fuel cost for the test year, plus the cost of purchased energy, wheeling and capacity, less the revenue from external sales of energy and capacity, is \$526,533,576 for 39,862,925 MWh, or \$0.01321 per kWh. These amounts include the total NSP system native energy requirements and costs to arrive at fuel cost data. The Commission finds that method to be appropriate in view of the Applicant's interchange

agreement with NSPM. A schedule showing monthly fuel cost estimates for the test year is attached as Appendix D.

Section PSC 116.04, Wis. Adm. Code, requires the Commission to establish monthly and annual ranges for the test year fuel forecast. If the Applicant's fuel costs exceed the monthly or cumulative range and a showing can be made that the annual range will also be exceeded, the Commission may hold hearings limited to the fuel cost question and may revise the Applicant's rates, if necessary.

The Commission finds that the following variance ranges are reasonable for the Applicant's fuel costs: (1) for the annual range, plus or minus 2 percent; (2) for the monthly range, plus or minus 8 percent; and (3) for the cumulative range, plus or minus 8 percent the first month of the test year, plus or minus 5 percent for the second month of the test year and plus or minus 2 percent for the remaining months of the test year. It is reasonable that the method of application of those ranges, established by the order in docket 4220-UR-110, continue to be utilized. It is appropriate to use the data in Appendix D for monitoring these ranges.

The Commission staff increased the sales estimate of NSPM by 415,019 MWh based on the updated sales forecast provided by Applicant. This increase in NSPM sales and a 40,847 MWh sales reduction for NSPW due to the loss of one large customer results in a material change in allocation factors for the interchange agreement. Applicant agreed that the new interchange allocation factors should be used in calculating revenue requirement for this proceeding. Commission staff increased NSP system fuel costs by \$6.08 million to serve this net increase in energy requirements. These changes would result in a reduction in the NSPW retail jurisdictional revenue requirement of approximately \$500,000.

The Commission staff reduced the Applicant's filed coal, oil, refuse-derived fuel (RDF), and wood costs by \$5.91 million to reflect current invoice prices increased by Applicant's filed escalation estimates. Gas generation costs were increased by \$989,000 to reflect the Applicant's updated natural gas cost forecast for 1998. Commission staff reduced the level of nuclear generation by 473,300 MWh due to the forced outage of Prairie Island for 5.5 weeks in the first quarter of 1998. This reduction in nuclear generation increases test year fuel costs by \$4.91 million. Commission staff also reduced purchase power capacity and energy costs by \$3.86 million resulting from Applicant's Operation Control (OC) contract with Manitoba Hydro Electric Board. The Commission finds these adjustments reasonable.

Commission staff reduced the Applicant's filed estimate of monitored transmission costs by \$2.74 million based on Applicant's revised estimate of these costs. The level of monitored transmission costs are increasing because of the substantial increase in the rates charged for third party impacts for non-requirements sales initiated by Mid-continent Area Power Pool (MAPP) through an approved Restated Agreement between its members. Applicant is getting a large increase in monitored transmission costs for the test year because certain non-requirement sales contracts were grandfathered at the lower rates until the sales contracts were renewed. Applicant is forecasting to renew these contracts for the test year. The Commission finds the adjustment to Applicant's revised estimate of monitored transmission costs to be reasonable.

### **Transmission Revenues**

Commission staff increased the Applicant's filed level of transmission revenues received associated with third party impacts to reflect a 33 percent increase above 1997 actual revenues received. Commission staff stated that the test year level should be higher than 1997 for the following reasons: increased transactions based upon more experience by MAPP members with transmission schedules with MAPP's Restated Agreement; renewal of grandfathered contracts previously exempt from MAPP's third party charges; and NSP has one of the most extensive transmission systems of MAPP members, therefore, additional purchases and sales transactions should result in third party revenues to NSP. Commission staff used the growth forecasted for transmission expenses of as a proxy for the growth for third party impact revenues.

In rebuttal testimony, Applicant stated that its revised estimate of transmission revenues \$3.4 million is a reasonable level for the test year. The 1998 test year estimate should be lower than 1997 actual because 1997 was an abnormal year due to capacity problems in eastern Wisconsin. Applicant also stated that the growth shown by Commission staff could not occur because of transmission constraints in MAPP as evidenced by the almost daily implementation of line loading relief in 1997.

The Commission determined that Applicant's test year estimate of transmission for the NSP system of \$3.4 million is reasonable. The transmission constraints will likely prevent the increase in transactions required to meet the revenue level proposed by Commission staff.

### **Deferred Decontamination And Decommissioning**

The Commission disallowed the collection of decontamination and decommissioning (D&D) assessments from the Department of Energy in the last rate proceeding docket 4220-UR-109. The Commission deemed the assessment invalid due to the U.S. Court of Federal Claims ruling in Yankee Atomic Electric Company vs. the United States, 33 Cl. Ct 580 (1995) that D&D assessments were unlawful. The order specified that the Commission would allow recovery in future rates if the Yankee Atomic decision was overturned. On May 6, 1997, the United States Court of Appeals for the Federal Circuit reversed the earlier decision by the Court of Federal Claims, 96-5021, 5025 (Fed. Cir., May 6, 1997). NSPW requested to collect the amount disallowed in the last rate proceeding in this test year by amortizing estimated deferred D&D costs as of June 1, 1998, of \$778,543 over 19 months or \$491,711 on an annual basis. The Commission determined this amortization of deferred D&D costs to be reasonable.

### **Wholesale Bulk Power Marketing**

NSP is planning to expand its participation in the wholesale bulk power market through a non-utility affiliate. NSP has assured the Commission it will continue to have employees actively participating in the bulk power market for marketing excess capacity as part of the utility. The Commission determined that NSP will need utility employees that actively participate in wholesale power for marketing excess capacity.

**Gas Sales and Other Gas Revenues**

Commission staff reduced NSPW’s estimate of total gas sales revenues to account for the loss of a large industrial customer and for an updated estimate of the cost of gas. A reasonable estimate of total test year gas sales and other revenues is \$89,580,000.

**Area Expansion Program Surcharges**

Revenues from surcharges, which are ordered to make gas service area expansions economically viable, should be recorded as contributions to the cost of construction and, ultimately, as credits to plant-in-service. This is in accord with the provisions of the Uniform System of Accounts.

**Estimated Net Income at Present Rates**

The following estimates of 1998 Wisconsin retail electric and gas operations are just and reasonable, for purposes of establishing just and reasonable rates in this proceeding:

<b>1998 Test Year</b>		
<b>Wisconsin Retail Operating Income Statement</b>		
	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Operating Revenues		
Sales	\$291,682	\$89,141
Other Operating Revenues	<u>2,066</u>	<u>439</u>
Total Operating Revenues	\$293,748	\$89,580
Operating Expenses		
Production Expense	\$145,517	\$ 228
Gas Storage Expense	-	206
Purchased Gas Expense	-	60,003
Transmission Expense	(2,886)	-
Distribution Expense	16,794	3,840
Customer Accounts Expense	5,794	1,210
Customer Service Expense	5,550	1,848
Sales Promotion Expense	335	53
Administrative & General Expense	<u>18,308</u>	<u>3,268</u>
Total Operation & Maintenance Expenses	\$189,412	\$70,656
Depreciation Expense	31,770	5,493
Amortization Expense	136	34
Taxes Other Than Income Taxes	12,209	1,534
State Income Taxes	3,253	700

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Federal Income Taxes	13,794	2,899
Deferred Income Taxes	1,852	340
Investment Tax Credit—Restored	<u>(732)</u>	<u>(55)</u>
Total Operating Expenses	\$251,694	\$81,601
Chippewa Flambeau Improvement Company Income	<u>34</u>	<u>-</u>
Net Operating Income	<u>\$42,088</u>	<u>\$ 7,979</u>

### Net Investment Rate Base

For purposes of determining just and reasonable rates in this proceeding, a reasonable estimate of NSPW's average net investment rate base for 1998 Wisconsin retail electric and gas utility operations is as follows:

	<b>1998 Test Year</b>	
	<b>Wisconsin Retail Net Investment Rate Base</b>	
	Electric <u>(000's)</u>	Gas <u>(000's)</u>
Utility Plant in Service	\$908,685	\$113,528
Less: Reserve for Depreciation	359,063	48,294
Accumulated Deferred Income Tax	<u>94,550</u>	<u>5,057</u>
Net Utility Plant in Service	\$455,072	\$ 60,177
Add: Investment in Associated Companies	534	-
Materials and Supplies	9,033	688
LNG Inventory	-	255
Gas in Storage	-	4,158
Deduct: Customer Advances	8,101	457
Amortization Reserve—Hydro	<u>3,513</u>	<u>-</u>
Average Net Investment Rate Base	<u>\$453,023</u>	<u>\$ 64,821</u>

### Pro Forma Rate of Return at Present Rates

Estimated operating revenues for 1998 for Wisconsin retail electric and gas utility operations would result in 9.29 and 12.31 percent rates of return on average net investment rate base for electric and gas utility operations, respectively.

## **Return on Rate Base**

### **Capital Structure**

A reasonable utility capital structure for the purposes of establishing rates for the test year consists of 54.996 percent common equity, 38.739 percent long-term debt, and 6.265 percent short-term debt.

The Commission finds that a long-term range of 52 to 57 percent for the utility's common equity ratio continues to be reasonable for NSPW. The exact level of the utility common equity ratio within that range may vary to provide flexibility to meet changing needs. NSPW should attempt to operate within that range in the long-term.

### **Return on Common Equity**

NSPW requested a return on common equity of 12.00 percent and provided expert testimony to support its request. Commission staff testified that a return of 11.25 percent would be appropriate for the test year.

In its determination of a fair return on common stock equity, the Commission must strike a balance between the interests of investors and those of consumers. It would be undesirable to allow a return on equity so high as to be excessive, just as it would be undesirable to allow a return so low as to discourage investors. The Commission must authorize a return on common stock equity that will provide adequate compensation for the risk assumed by owners of the Applicant's common stock. The authorized return on common stock equity should be commensurate with earnings of other business enterprises that have similar risks, maintain the financial integrity of the utility, attract and hold capital at reasonable costs, and protect the interests of utility customers.

In view of the above considerations, the Commission considers an 11.90 percent return on utility common stock equity to be reasonable in this proceeding for the purpose of establishing just and reasonable rates.

### **Costs of Short-Term and Long-Term Debt**

Based on the economic forecasts for commercial paper rates, a reasonable cost of short-term debt is 5.763 percent for the test year. Included in this cost is an administrative charge to cover the administrative costs of the parent company, NSPM, which supplies short-term debt funds to NSPW. If NSPW issued its own short-term debt, it would also incur similar costs. The embedded cost of long-term debt for NSPW is 7.29 percent.

**Weighted Cost of Capital**

Accordingly, the average capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable for setting just and reasonable rates for the test year are as follows:

	Amount (000's)	Percent		Annual Cost Rate		Weighted Cost
Utility Common Equity	\$ 331,636	54.996 %		11.900 %		6.54 %
Long-Term Debt	233,600	38.739		7.290		2.82
Short-Term Debt	<u>37,781</u>	<u>6.265</u>		5.763		<u>0.36</u>
Total Utility Capital	\$ <u>603,017</u>	<u>100.000 %</u>				<u>9.72 %</u>

The resulting weighted cost of capital of 9.72 percent is reasonable for NSPW in the test year and generates an economic cost of capital of 14.10 percent and a pre-tax interest coverage ratio of 4.43 times.

**Additional Revenue Requirement Related to the Viking Gas Transmission Company**

In docket 4220-UR-107, the Commission ordered an additional amount of revenue requirement for NSPW in connection with NSPM's acquisition of the Viking Gas Transmission Company. For the 1998 test year this amount would be \$421,000. To accommodate the biennial rate case process (which was not in effect at the time of the 4220-UR-107 order) Commission staff reduced this amount by 50 percent to \$210,000. This is because the rates set in this docket are designed to be in effect for 2 years. In addition, the reporting requirement relating to the economic benefit of Viking to NSPW's customers no longer serves the purpose it was designed for since this is the last year of the additional revenue requirement. This report may be discontinued.

**Return on Capitalized Conservation**

The Commission’s current policy allows NSPW to earn a return on its capitalized conservation balance by providing an addition to the rate of return on net investment rate base. The DSM/conservation accounting policy change allowed in the order in docket 4220-UR-108, as previously discussed, provides that NSPW may discontinue capitalizing DSM/conservation incentive expenditures. However, that policy change did not eliminate the already-capitalized balance of DSM/conservation incentive expenditures. That balance will continue to be amortized over a ten-year period, as had been done in the past. Therefore, NSPW should be allowed to continue earning a return on its capitalized conservation balances. These returns will be provided as additions of 0.08 and 0.16 percent to the rates of return on net investment rate base for electric and gas utility operations, respectively.

This is accomplished by dividing the weighted cost of capital by the ratio of net investment rate base plus construction work in progress and conservation investments to capital applicable primarily to the utility operations plus deferred investment tax credits (ratio). A return on the remaining capitalized DSM/conservation investments and the return due to the Viking revenue requirement adjustment (for gas), which are not technically part of the rate base, must also be added. The calculation of the appropriate rates of return on rate base is shown below:

	<u>Electric</u>	<u>Gas</u>
Weighted Cost of Capital	9.72%	9.72%
Ratio	95.60%	95.60%
Return on Rate Base	10.17%	10.17%
DSM/Conservation Return Adjustment	0.08%	0.16%
“Viking” Acquisition Adjustment	-	0.19%
Adjusted Return on Rate Base	10.25%	10.52%

The Commission finds that rates of return on rate base of 10.25 and 10.52 percent for electric and gas utility operations, respectively, are sufficient to establish reasonable rates in this proceeding.

**Revenue Deficiency (Excess)**

On the basis of the findings in this order, the Commission finds that a \$7,256,000 increase in electric revenues and a \$1,936,000 decrease in gas revenues are reasonable and just, computed as follows:

	<u>Electric</u> <u>(000's)</u>	<u>Gas</u> <u>(000's)</u>
Authorized Return on Average Net Investment Rate Base	10.25%	10.52%
Average Net Investment Rate Base	\$453,023	\$64,821
Required Net Operating Income	\$ 46,435	\$ 6,819
Utility Net Operating Income at Present Rates	\$ 42,088	\$ 7,979
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base	\$ 4,346	\$ (1,159)
Revenue Deficiency (Excess) to Provide for Earnings Deficiency (Excess) Plus Federal and State Income Taxes	\$ 7,256	\$ (1,936)

**Ten-Year Financial Forecast**

NSPW submitted a ten-year financial forecast in this proceeding. The forecast is useful in assessing the reasonableness of the capital structure and the required return on equity. Therefore, NSPW should submit a revised ten-year financial forecast in its next rate filing.

**Demand-Side Management (DSM)**

**Natural Gas Sales Promotion**

NSPW proposed to continue its two-year natural gas sales promotion plan that was approved by the Commission in the order from docket 4220-UR-109 covering 1997 and 1998. The company argued that it should be able to complete its two-year plan and should be able to recover one-half of the \$246,407 annual budget in 1998 and the other half in 1999.

Commission staff offered the Commission two options for consideration on natural gas sales promotion: 1) Zero out the proposed annual gas sales promotion budget of \$246,407 for 1998 and 1999. NSPW has not provided any compelling justification to continue with its gas sales promotion efforts as required in the 4220-UR-109 order. 2) Allow NSPW to continue to

implement its approved 1997-1998 two-year natural gas sales promotion plan and approve an annual budget of \$123,204 for 1998 and 1999.

The Commission found in the order from docket 4220-UR-109 that NSPW shall assume “zero-based budgeting” for gas sales promotion in the expenses in the future. This requires that all gas sales promotion dollars must be justified in future rate cases. NSPW has completed most of its two-year 1997-1998 gas sales promotion plan and has not provided any new justification for the continuation of its gas sales promotion efforts in this docket. The Commission finds that it is reasonable to zero out the natural gas sales promotion budget for 1998 and 1999.

### **1998 and 1999 DSM Goals**

#### **Natural Gas Energy Savings Goals**

NSPW proposed that it should receive a 25 percent reduction in its residential and rental quantitative gas goals and a 15 percent reduction in its commercial and industrial gas goals for 1998 and 1999 in exchange for implementing its proposed market preparation activities. NSPW argued that the reduction in gas goals they were proposing was consistent with the reduction in electric energy savings goals agreed to with Commission electric division staff.

For several years, Commission natural gas division DSM staff has been working with natural gas utilities in the state to develop qualitative market preparation goals in trade for a reduction in quantitative natural gas energy savings goals. This process has been approved by the Commission in several dockets and has been offered to all of the natural gas utilities when setting goals. As a result, a portion of each utility’s quantitative goals has evolved into market preparation goals. The amount of quantitative gas goal reduction is based on the level of effort and rigor that a natural gas utility is willing to apply to market preparation activities and their associated evaluation. A 5 percent reduction in quantitative natural gas DSM goals for all sectors, except low income, is given for good faith market preparation activities undertaken by the utility to prepare the market for public benefits. If a natural gas utility is willing to develop a detailed description of market preparation programs and an evaluation plan that are consistent with Commission staff’s guidelines, a reduction of up to 25 percent in the quantitative natural gas DSM goals is reasonable. Larger reductions in the quantitative natural gas DSM goals are possible if the utility is willing to develop specific market preparation goals and evaluate the levels of achievement associated with them.

The Commission has already recognized the market preparation activities that NSPW is proposing for additional credit. In return for NSPW’s commitment to deliver market preparation programs in the residential and commercial sector and the associated evaluations of these programs, the Commission approved a 10 percent reduction of NSPW’s Commercial and Industrial (C&I) natural gas energy savings goals for 1996 in docket 4220-UR-108. This reduction was carried over into 1997 in exchange for NSPW continuing to pursue its qualitative market preparation activities.

The Commission finds that an additional 5 percent decrease in the 1998 natural gas DSM corporate goal, except for low-income, is consistent with the process that has been used with other natural gas utilities in the state and with Commission natural gas division DSM staff's guidelines. The Commission finds the following 1998 gas energy savings goals and minimum sector targets to be reasonable and appropriate:

<u>Sector</u>	<u>Therm Goal</u>	<u>Minimum Target</u>
Residential	197,125	155,635
Commercial	693,975	547,875
Industrial	575,580	454,406
Rental	50,350	39,750
<u>Low Income</u>	<u>62,125</u>	62,125
Total Corporate Goal:	1,579,155 Therms (Gross)	

If NSPW develops detailed program descriptions and an evaluation plan for its market preparation activities for 1999, the Commission finds that an additional 20 percent reduction in the residential and rental sector goals and an additional 10 percent reduction in the commercial and industrial sectors are reasonable and appropriate. The programs and evaluation plan should be consistent with Commission staff's guidelines. The following would be the 1999 gas energy savings goals and minimum sector targets:

<u>Sector</u>	<u>Therm Goal</u>	<u>Minimum Target</u>
Residential	157,700	118,275
Commercial	624,575	468,430
Industrial	518,000	388,500
Rental	40,275	30,200
<u>Low Income</u>	<u>62,125</u>	62,125
Total Corporate Goal:	1,402,675 Therms (Gross)	

### **Electric Energy Savings Goals**

The Commission finds it reasonable and appropriate to establish for each of 1998 and 1999 a total NSPW company electric DSM goal of 48.0 GWh. Within the total company goal, an electric low-income goal of 564,775 kWh is reasonable. NSPW indicated during the hearings in this proceeding that it agreed with these goal levels. Establishing these goal levels is consistent with the Commission's recent electric industry restructuring directions and with the Advance Plan 7 (docket 05-EP-7) decision on maintaining flat DSM goals in the restructuring transition period.

The Commission approves of the agreement reached between Commission staff and NSPW to allow up to 25 percent of the 1998 goal (12.0 GWh) to be met through DSM market preparation efforts in 1998. NSPW will receive credit for 1 GWh of savings goal for every \$93,000 actually spent in 1998 on NSPW proposed and Commission staff approved market

preparation activities. Programmatic results should not be counted both towards savings and for credit against the goal.

### **Electric Residential Sector Goal**

In the recent past, it has been the Commission's intent to allow utilities some flexibility in which sectors it finds the DSM savings to meet Commission DSM goals. This is why the Commission stopped its practice of setting electric DSM sector goals for NSPW and other utilities in 1995. This does not mean, however, that the Commission is no longer concerned about the adequacy of and equity of the DSM services offered to different customer sectors. The Commission finds that the recent performance and trends in performance of NSPW in delivering conservation services to the residential electric customer sector is cause for concern. The Commission finds that it is appropriate to re-establish residential sector electric energy savings goals for NSPW for 1998 and 1999.

A residential electric DSM energy goal of 12.4 annual GWh is reasonable and appropriate for NSPW for each of the years 1998 and 1999. This is the level of the residential electric target set by the Commission for NSPW for 1995. By approving this level of residential goal, the Commission reaffirms its commitment to allowing no backsliding on demand-side management efforts.

### **Low- Income Energy Efficiency**

NSPW argued that it was cost-effectively achieving its low-income DSM goals currently and that it should not be required to increase its low-income budget for 1998 and 1999. The proposed annual low-income budget of \$303,184 is adequate to meet the 1998 and 1999 low-income DSM goals.

Commission staff proposed to increase NSPW's low-income energy efficiency budget by \$101,816. The budget increase was proposed because NSPW is currently spending less than its reasonable share of program expenses in order to claim credit for savings. By increasing funding to a level that is at least 50 percent of total program costs, it is hoped that more comprehensive services can be provided and state weatherization programs can be supported adequately during any prospective transition to alternative provision and recover of so-called public benefits activities.

The Commission recognizes that state weatherization programs have lost a considerable portion of their federal funding in the last several years. They have come to rely more heavily on utility programs to make up for some of those losses. In order for the state to retain the infrastructure necessary to provide comprehensive services to all low-income customers who need it during any prospective transition to alternative provision and recover of so-called public benefits activities, the Commission finds it reasonable and appropriate to increase NSPW's 1998 and 1999 annual low-income budget by \$101,816 to \$405,000.

In addition, Commission staff proposed that NSPW be required to follow a set of transitional funding and delivery guidelines for utility low-income energy efficiency programs. The guidelines are as follows:

### **Funding**

- 1) All Wisconsin utilities should maintain and/or increase their level of overall funding for low-income energy efficiency programs if necessary to meet their energy savings goals.
- 2) All Wisconsin utilities should pay up to 100 percent of the costs of delivering and installing energy conservation measures, if necessary, to complete the work determined as cost-effective by the state Energy Audit Bureau. Cost-sharing with state weatherization operators should not be a barrier to utilities meeting their energy savings goals.
- 3) All utility payment for contracted services should be based on compensating providers for energy saved. Compensation should be based on \$ per kWh and therm saved. The \$ amount per kWh and therm should be determined, at minimum, by covering 50 percent or more of the contractor's cost of administering and delivering energy efficiency services at the program level.
- 4) All Wisconsin utilities shall establish a goal of holding their internal administrative costs to 15 percent or less of total program costs.

### **Delivery**

- 1) All Wisconsin utilities will deliver or pay for the delivery of comprehensive energy efficiency services to its low-income customers when determined to be cost-effective by the state energy audit. Comprehensiveness includes non-energy savings benefits like improvements to or maintenance of the health, comfort and safety of the treated building.
- 2) All Wisconsin utilities will consider contracting with other providers if state weatherization operators cannot deliver and install conservation measures sufficient to achieve energy savings goals.

NSPW argued that it should not be required to follow Commission staff's proposed guidelines. Instead, there should be a generic hearing to discuss them in the context of utility transition plans. Commission staff submitted a memo for the Commission's agenda on November 3, 1997. In this memo, entitled "Demand-Side Management Issues and Initiatives," Commission staff described its review and critique of utility performance in 1996, each utility's DSM Transition Plan, and the results of research on the feasibility of implementing four program designs from Advance Plan 7. In commenting on Commission staff's recommendations, the Commission determined that utility DSM performance (in 1996) indicated a trend toward

underachievement in the residential/rental and low-income sectors. It also found that utilities have reduced their financial and staff commitments to DSM achievement in small customer markets. The Commission also determined that an intensive focus on the low-income sector was required.

As part of the Commission's direction on the Transition Plans, Commission staff is to propose possible solutions to the funding and goal achievement problems that have been exhibited by some utilities. The Commission finds that the low-income guidelines proposed by Commission staff, as listed above, in this case are reasonable and appropriate.

### **Electric Rates**

Authorized final electric rates, shown in Appendix B, will provide annual Wisconsin retail electric revenue from rates of \$298,938,000 (excluding other operating revenues).

#### **Revenue Allocation**

NSPW based its revenue allocation on its embedded cost-of-service study and its requested electric revenue increase. Commission staff based its revenue allocation on NSPW's embedded cost-of-service study, adjusted for Commission staff's lower revenue requirement. Selection of final class revenue targets, using NSPW's embedded cost-of-service study as a guideline and adhering to the general principles of rate-making, is largely a matter of judgment. The Commission has exercised its judgment and allocated revenues based on the record in this proceeding, adopting the revenue allocation proposed by the Commission staff as adjusted for the final revenue requirement.

#### **Electric Rate Design**

Both Applicant and Commission staff submitted rate designs in this proceeding. In order to attain rate continuity and achieve the goals of customer understanding and acceptance of rates, the Commission has considered NSPW's embedded cost-of-service study and customer bill impacts in the rate design authorized in this order. The Commission adopts Commission staff's rate design. The Commission finds that the rates that appear in Appendix B properly reflect costs, recover the appropriate amount of revenue from each class, appropriately consider bill impacts and are therefore reasonable.

The Commission reaffirms its position that flat energy charges are appropriate to promote conservation and that time-differentiated energy charges should be related to marginal costs to provide the proper price signal. The rates authorized by the Commission, as shown in Appendix B, are a continuation of Applicant's current rate structure with adjustments to meet the revenue requirement.

NSPW proposed decreasing the monthly Load Management credit for residential water heating by \$1.00 to better reflect cost. Commission staff concurred with this rate change. The Commission finds it reasonable to decrease the monthly Load Management credit for residential water heating as shown in Appendix B.

Applicant also proposed a number of changes to specific tariff language. Among these are expanding the availability of the Cg-6 rate to residential and farm customers and increasing the off-peak time period for this rate, changing the power factor provision for the Cp-1 and Cp-2 tariffs, and changing the minimum power factor requirement for the Mp-1 rate class to 90 percent. NSPW also proposed some clarifications to specific tariff language. Commission staff concurred with these changes. The Commission finds it reasonable to accept NSPW's proposed tariff language changes which appear in Appendix B.

NSPW proposed a change in the language of the processing charge provision to require a charge of \$16.50 be applied in cases in which a landlord does not want the electric or natural gas service put in his/her name during the time between tenants and requests NSPW lock the meter. Commission staff concurred with this proposal. The Commission finds it reasonable to accept the proposed change to the processing charge which appear in Appendix B.

Commission staff proposed renaming the Customer Demand Charge to Distribution Demand Charge. NSPW did not object to this change. The Commission finds it reasonable to accept this renaming change proposed by Commission staff.

### **Buy-back Rates**

Applicant proposed to maintain the current Pg-2, Parallel Generation - Energy Purchase Service rates at the present level. Applicant testified that the forecasted avoided cost is only slightly less than the current buy-back rates. Applicant also proposed maintaining the current Pg-2.2, Parallel Generation - Hydroelectric Energy Purchase Service energy rate at its current level, since there is one customer taking service on this rate. Commission staff concurred with Applicant's proposal. The Commission finds it reasonable to maintain the current Pg-2, Parallel Generation - Energy Purchase Service rates and the Pg-2.2, Parallel Generation - Hydroelectric Energy Purchase Service rates, as shown in Appendix B.

### **Experimental Real-Time Pricing Service**

NSPW proposed changes to the Real-Time Pricing (RTP-1) rate consistent with its Cg-9 rate design. NSPW also proposed extending the experimental time period to January 31, 1999. Commission staff proposed changing the Real-Time Pricing (RTP-1) rate to be consistent with its rate design for Cg-9. Commission staff concurs with the proposal to extend the experimental time period until January 31, 1999. The Commission finds it reasonable to approve the RTP rate design proposed by Commission staff as well as extending the experimental time period to December 31, 1999.

### **Residential Time-of-Day (Rg-2) Rate Availability**

NSPW proposes to eliminate the mandatory nature of the Residential Time-of-Day (TOD) rate. Commission staff suggested an alternative which would be consistent with other utilities' mandatory residential TOD rate provisions. Currently, several of the major

investor-owned utilities in Wisconsin have a mandatory provision in their residential TOD rate tariffs. These availability provisions require residential customers with usage greater than a certain level to be billed on a TOD rate. Both Wisconsin Power and Light Company and Wisconsin Electric Power Company rates require residential customers with annual usage greater than 60,000 kWh to be billed on a TOD rate. The Commission finds it reasonable to require NSPW to change the availability clauses for the residential service tariffs to require all residential customers with annual usage greater than 60,000 kWh to be billed on the Rg-2 rate.

## **Natural Gas Rates**

### **Natural Gas Cost-of-Service Studies**

NSPW provided one embedded cost-of-service study based on the company filed revenue requirement for the 1998 test year. Commission staff did not perform a cost-of-service study for this docket. However, Commission staff prepared two cost-of-service studies using a 1997 test year in NSPW's last rate case, docket 4220-UR-109, which established the base case for the proposed NSP/Wisconsin Electric Power Company merger. The natural gas revenue requirement did not change in docket 4220-UR-109 and no rate changes were made. Commission staff relied on the results of the two cost-of-service studies from docket 4220-UR-109 to provide a general guideline for rate design in the current docket.

The Commission finds that the cost-of-service studies presented in this docket are reasonable guidelines for designing rates in this case.

### **Natural Gas Rate Design**

Commission staff proposed a rate design that apportioned a slightly larger part of the distribution revenue decrease to firm customers based on the cost-of-service study results. NSPW and the Wisconsin Paper Council agreed with Commission staff's proposed rate design. The Commission finds that Commission staff's proposed rate design is reasonable.

### **Interruptible Service (Ig-1) Customer Charges**

Commission staff proposed increases in the customer charges of Groups 1, 2, 3, 4, and 5 of the Ig-1 interruptible service customer classes. NSPW opposed increases in the Group 1 and 2 customer charges, but did not oppose increases in the Group 3, 4, and 5 customer charges. Based on an analysis of customer-related costs, Commission staff agreed to retain Group 1 and 2 customer charges at current levels. The Commission finds that retaining the current customer charges for Ig-1 Group 1 and 2 customers and increasing the customer charges for Ig-1 Group 3, 4, and 5 customers to \$350.00, \$500.00, and \$625.00 respectively is reasonable.

### **Removal of Gas Supply Costs from the Distribution Costs**

A significant step in moving towards the new functional cost-of-service categories, approved in the natural gas restructuring docket (05-GI-108 Phase I), is the removal of gas

supply costs from the rates for distribution service. The distribution service rates are paid by both system sales and transportation customers. Since transportation customers procure their own gas supplies, gas supply costs should not be borne by transportation customers. Commission staff identified gas supply costs totaling \$2,295,000 that are currently being collected through the rates for distribution service. These costs are comprised of gas supply purchasing personnel expense, the cost of peaking plants, the carrying cost of gas in storage and the portion of gross receipts tax that is based on gas sales revenues.

NSPW agreed with Commission staff's proposal to remove gas purchasing personnel expense, the cost of peaking plants and the carrying cost of gas from the distribution costs, but opposed the removal of the portion of gross receipts tax paid on gas sales revenues. NSPW took the position that the gross receipts tax, including that portion of the tax paid on gas sales revenues, should be paid by all customers because gross receipts tax is a substitute for property tax. Commission staff acknowledged that the gross receipts tax replaces other taxing methods that utilized property tax. However, Commission staff did not agree that the portion of the gross receipts tax paid on gas sales revenues should be collected from transportation customers because transportation customers do not use utility gas.

The Commission finds that removing the gas supply costs consisting of gas cost purchasing personnel expense, the cost of peaking plants, the carrying cost of gas in storage and the gas sales revenue portion of gross receipts tax from the distribution margin is reasonable and is consistent with decisions made in other rate cases. The Commission agrees with Commission staff that the gross receipts tax is not a direct substitute for property tax and that gross receipts tax paid on gas sales revenues should not be paid by transportation customers.

### **Recovery of Gas Supply Costs**

Commission staff proposed to recover the gas supply costs removed from the rates for distribution service on a per therm basis from only system sales customers because transportation customers should not pay these costs. NSPW agreed with the Commission staff proposal. The Commission determines that it is appropriate to recover gas supply costs on a per therm basis from system sales customers.

### **Itemization on Customer Bills**

Commission staff recommended categorizing charges on customer bills as utility service and gas supply service. Additionally, Commission staff recommended that the customer charge, distribution service charge, gas supply charge, gas base rate and gas adjustment rate be separately itemized to promote customer information and understanding of services. NSPW opposed separately identifying the gas-related charges as unnecessary and confusing to customers. The Commission determines that it is reasonable for Commission staff and NSPW to work together to develop a billing format that provides appropriate and useful information on customer bills.

### **Unauthorized Use Penalty Incremental Cost Language**

NSPW proposed the addition of language that more fully describes the calculation of incremental costs incurred by the utility due to unauthorized use of natural gas. Commission staff agreed that this language clarifies how incremental costs are determined and when such charges will be assessed to customers. The Commission finds that it is reasonable to add this clarifying language to the tariff provisions pertaining to the unauthorized use of natural gas.

### **Incidental Use Provision of the Unauthorized Use Penalty**

NSPW recommended changing the basis for calculating incidental use from 5 percent of the current month's average daily use to 5 percent of the previous month's average daily use or 5 percent of the prior year's current month's average daily use, whichever is greater, up to a cap of 100 therms. Commission staff agreed with this change which allows more timely billing of unauthorized use charges. The Commission finds that it is reasonable to make this change in the incidental use language.

### **Geographical Considerations in Priority of Service**

NSPW proposed the addition of language clarifying that geographical considerations may cause the company to continue service to customers with a lower priority of service in one area while curtailing or interrupting service to other customers with an equal or higher priority of service in another area due to supply and capacity situations that may vary across the NSPW system. Commission staff agreed with the addition of this language. The Commission finds that it is appropriate to incorporate this clarifying language.

### **Telemetering for Interruptible Customers**

NSPW proposed to require telemetering for Ig-1 Group 1 interruptible customers and Lg-1 partially interruptible customers. Commission staff agreed that daily usage information of interruptible customers is necessary to assure compliance with interruption and curtailment orders. The Commission finds that requiring Ig-1 Group 1 and Lg-1 customers to be telemetered is reasonable in order to assure customer compliance with interruption and curtailment orders.

### **Rental Account Processing Fee**

NSPW recommended a change in the rental account processing fee which allows the landlord to place an account in his or her name between tenants without charge. Additionally, the company proposed a charge of \$16.50 if NSPW is required to lock the meter between tenants. Commission staff agreed that these changes would recover the cost of additional trips to lock or unlock the meter and make it more likely that the account would be placed in the landlord's name so that any usage between tenants would be billed to the landlord. The Commission finds that these changes in the rental account processing fee are reasonable.

### **Notification Period for Customers to Switch between Gas Supply Schedules**

The company proposed to significantly shorten its notification period for customers that choose to move between gas supply schedules. Currently, a customer must notify the company at least 12 months prior to November 1 of the year preceding the proposed transfer date. The current notice requirement makes the possible waiting period for the customer to change schedules between 12 months and 24 months, depending upon when the customer provides notice to the company.

The company proposed to allow a customer that provides notice before May 1 to change gas supply schedules on or after May 1 of the same year. The proposed notice period shortens the possible waiting period for the customer to change schedules to between one day and 12 months. The company indicated that shortening the notice period would reduce a barrier to transportation because customers would be able to act on a choice to move to transportation service more quickly. By May 1 seasonal collection of peak demand costs is completed so any customer leaving the system on or after May 1 would pay all peak demand costs for the past winter. Additionally, with notice by May, the company could adjust its contracted capacity for the upcoming heating season.

Commission staff agreed with the company's proposal to allow customers to switch gas supply schedules by providing notice by May 1. The Commission finds that this change in the notification period is reasonable.

### **Gas Management Service**

Commission staff proposed a change in the Gas Management Service (GMS) availability clause limiting the service to interruptible distribution customers whose revenues would be lost without access to GMS. NSPW proposed to continue to offer GMS as a customer service option to all interruptible distribution customers. Commission staff based its recommendation on concerns about the dearth of non-GMS transportation customers in NSPW service territory; the separate gas supply packages purchased for GMS customers which are bundled with utility release capacity; and the possible supercompetitiveness of GMS service versus the services of marketers.

The Commission is concerned that limiting GMS might produce detrimental consequences to customers and utility revenues at times during the year when these customers might be price-sensitive. The Commission determines that GMS should continue to be offered as a customer choice to all interruptible distribution customers at this time. However, due to anticompetitive concerns, the appropriateness of maintaining GMS in its current form will be reexamined in the next rate case.

### **Gas Cost Recovery Mechanism (GCRM)**

The order in docket 05-GI-106 (the GCRM docket), issued November 8, 1996, directed that LDCs whose sales are equal to or exceed those of Superior Water, Light and Power

Company shall use either an incentive Gas Cost Recovery Mechanism (GCRM) or a modified one-for-one GCRM. NSPW filed testimony and exhibits proposing a modified one-for-one recovery mechanism. The proposal was considered in this rate case.

The proposed GCRM consists of four components for tracking and collecting gas costs: 1) the Peak Day Capacity Cost Component; 2) the Supply Reservation Cost Component; 3) the Transition Cost Adjustment Component; and 4) the Commodity Cost Component.

### **The Peak Day Capacity Cost Component**

The peak day capacity cost component includes costs for pipeline capacity and the peak day deliverability component of contracted storage services. NSPW proposes one-for-one recovery for these costs with an ongoing true-up as is currently allowed in the Purchased Gas Adjustment mechanism (PGA). The difference between the proposed GCRM and the current PGA, in this area, is the proposal for capacity release credits.

As proposed by NSPW, the peak day capacity cost component would consist of the following three types of costs:

#### **1. Pipeline Capacity Costs**

Pipeline Capacity Costs includes the costs for both upstream and deliverable capacity. This includes the costs paid for pipeline capacity held by natural gas suppliers who sell to the utility.

#### **2. Storage Deliverability Costs**

Storage Deliverability Costs includes the peak day deliverability portion of the costs of contracted storage services. Contracted storage services are a multi-part rate. Only the fixed portion of the rate, which is based on the amount of gas that can be delivered on a peak day (the deliverability charge), is included in this portion of the proposed GCRM.

#### **3. Capacity Release/Opportunity Sales Revenue Credit**

Capacity Release/Opportunity Sales Revenue Credit includes the revenues that are received by the utility in the following types of transactions: a) non-recallable release of excess capacity; b) recallable release of temporarily unneeded capacity; c) revenues resulting from the flex-up provision of the interruptible system tariff; d) bundled sales to end-users (gas management service customers, other local distribution companies or marketers); e) swaps or other type of exchanges; and (f) unbundled commodity sales. NSPW proposes that the revenues associated with items (b) through (f) be shared, with 75 percent of the revenues accruing to ratepayers and 25 percent of the revenues accruing to shareholders.

The Commission's order in docket 05-GI-106 (the 106 Order) required that modified one-for-one GCRMs incorporate forecasted (targeted) levels of opportunity sales. The 106

Order permits a sharing mechanism for capacity release/opportunity sales revenues in excess of the targeted level. NSPW and Commission staff concurred that the targeted capacity release/opportunity sales volume for each month will be based on the level of capacity above the design day for that month as identified in NSPW's approved supply plan. Therefore, revenue from that excess capacity (capacity above design day) would not be subject to any sharing mechanism, but credited back to the ratepayers.

There was considerable discussion on the record and in briefs concerning which type of transactions constituted opportunity sales subject to the sharing mechanism. NSPW's proposed GCRM included in the opportunity sales sharing mechanism revenues from interruptible flex-up and GMS tariffs as well as revenues from swaps and other types of exchanges.

NSPW argued that interruptible flex-up and GMS transactions were functionally equivalent to opportunity sales since both utilized the utility's unused or underutilized capacity. NSPW, additionally, argued that the Commission had previously authorized NSPW to share in revenues generated from interruptible flex-up transactions and that this authorization should be extended to the GMS transactions because of similarities in risks. NSPW argued that swaps expressly fall within the definition of opportunity sales and, therefore, should be subject to the sharing mechanism.

Commission staff argued that GMS and interruptible flex-up are tariffed services; there is statutory obligation on the utility's part to serve these customers that is not present in the case of opportunity sales. Opportunity sales are made when the "opportunity" presents itself, whereas the provision of tariffed service is an ongoing obligation. GMS and interruptible flex-up are not sales into the unregulated markets, but are tariffed provisions of utility service. They utilize unused system capacity but that capacity is not offered to the market under the conditions detailed in the Natural Gas Standards of Conduct, docket 05-GI-108, Phase II.

On the issue of whether or not a swap is an opportunity sale, Commission staff argued that the critical distinction is not the type of transaction (i.e., capacity, supply, storage, bundled, buy-sells, swaps, loans, city gate) but whether or not the assets involved were unused or underutilized assets held for the system. It would not be appropriate for shareholders to share in revenues generated in a swap involving assets needed for the system. Sharing of revenues from such transactions would raise questions of prudence on the part of the utility and would create a financial incentive for the utility to make transactions regardless of their impact on system reliability. Swaps that utilize assets needed for the system (not unused or underutilized) are a method of managing gas procurement costs. They are simply another supply alternative and should be treated as such for GCRM purposes.

The Commission finds that NSPW's proposal for the pipeline capacity cost and storage deliverability cost pieces of the peak day capacity cost component of the GCRM are reasonable. However, the Commission finds that it is reasonable that NSPW's capacity release/opportunity sales revenue credit portion of the peak day capacity cost component be modified as suggested by Commission staff. Therefore, the capacity release/opportunity sales revenue credit shall include opportunity sales as defined by the Commission in the order in docket 05-GI-108,

Phase II and clarified in this order. Opportunity sales shall be defined as the sale or release of the utility's unused or underutilized capacity and supply entitlements that become periodically available because of the variable daily and seasonal needs of customers. This definition of opportunity sales encompasses swaps that involve unused and underutilized assets held for system use. Swaps that utilize a mixture of used and unused assets will be excluded. Revenues from interruptible flex-up and GMS tariffs will not be included as opportunity sales and will not be subject to the sharing mechanism. Opportunity sales subject to the sharing mechanism shall be those sales in excess of the target level for capacity release/opportunity sales. The target level for capacity release/opportunity sales volume for each month shall be based on the level of capacity above the design day for that month, as identified in NSPW's approved supply plan. The Commission finds it reasonable that the capacity release/opportunity sales revenues available for sharing should be shared with 75 percent of the revenues accruing to ratepayers and 25 percent of the revenues accruing to shareholders. The Commission also finds it reasonable that the capacity release/opportunity sales revenues not available for sharing (capacity above design day) be credited 100 percent to the ratepayers.

### **The Supply Reservation Cost Component**

The supply reservation cost component is intended to recover fixed costs related to supply reliability and other non-commodity costs not directly related to peak day capacity needs. NSPW proposed a one-for-one recovery for these costs with an on-going true-up as is currently allowed in the PGA. The Supply Reservation Cost Component consists of the following five basic parts:

#### **1. Supply Reservation Costs Paid to Supplier**

Supply Reservation Costs Paid to Supplier are the reservation fees on long term contracts. For NSPW, these costs are reflective of the supplier reliability premiums and are alternatives to high minimum take requirements.

#### **2. Storage Capacity Costs**

Storage Capacity Costs are the costs for the annual capacity portion of the cost of contracted storage services. These are the fixed charges based on the volumetric amount of capacity reserved in the storage field (i.e., that portion of the multi-part storage rate related to reliability). The fixed portion of the multi-part rate based on the amount of gas that can be delivered on a peak day (deliverability charge) is included in the Peak Day Capacity Cost Component. Other storage charges that are variable in nature and based on injections and withdrawals are allocated to the Commodity Cost Component of the GCRM.

#### **3. Miscellaneous Fixed Costs**

Miscellaneous Fixed Costs include no-notice service/system management service (SMS), system balancing agreement (SBA) surcharges, GRI charges, gas inventory charges (GIC) for undertakes and credits for daily balancing revenues. SMS and SBA are related to reliability of

service and, therefore, are similar to a reliability premium. Revenues from daily balancing are credited to this component to offset fixed costs associated with SMS and SBA. GICs are charges under long-term contracts, incurred when actual takes under the individual contract fall below a minimum level. GICs are similar to supply reservation fees or high minimum takes in that they are another method of ensuring reliability. NSPW has proposed to seek approval before any GIC charges are passed through this component of the GCRM.

#### **4. Propane/City Gates Sales Adjustment**

Propane/City Gate Sales Adjustment consists of the portion of city gate purchases or propane above (or below) the commodity benchmark.

NSPW argued that city gate purchases and propane air are simply alternative methods of serving firm customers, compared to purchasing commodity and increased pipeline capacity. NSPW offered to show propane and city gate sales as separate lines in the Standard Reporting Format and, where possible, to seek approval from Commission staff before applying their proposed treatment.

Commission staff argued that city gate purchases should be treated like any other commodity purchase, indexed at the benchmark, and included in the commodity cost component of the proposed GCRM, thereby eliminating the need for additional filings on the part of the utility and making the review of costs in excess of the benchmark automatic. NSPW already has sufficient capacity under contract that it, generally, should not be paying a premium over index price for city gate deliveries. Certain situations may occur where this may be appropriate, but those occurrences would be rare, and can be reviewed on a case by case basis.

Commission staff argued that currently propane costs are not allowed through the purchase gas adjustment mechanisms. Before propane costs can be allowed to pass through the GCRM, monitoring procedures will have to be developed and implemented in the GCRM review process. An appropriate index for propane would also need to be developed. In addition, for each LDC system, the interactions between capacity release, interruptible load and propane use must be identified and understood. Allowing propane cost to flow through the GCRM mechanism before these interactions are understood would risk creating incentives to utilize propane to create or maintain opportunity sales revenues rather than ensuring system integrity. Historically, propane has not been a significant gas cost assuring that any postponement of the decision on propane in the GCRM will not cause undue harm to NSPW. Commission staff argued that if, in the future, the Commission allows propane costs through the GCRM, propane should be treated like any other supply source, and indexed at a benchmark and flowed through the commodity cost component of the GCRM.

#### **5. Commodity Component True-up**

Commodity Component True-up consists of any approved true-up of the differences between the actual commodity cost and the benchmark commodity cost.

NSPW's proposed to flow these costs through the supply reservation cost component rather than through the commodity cost component. NSPW argued that including the commodity cost true-up in the supply reservation component of the GCRM would minimize any distortion of the price signals provided by the benchmark price. NSPW argued that including in the commodity cost component causes confusion when dealing with subsequent cost/benchmark reconciliations.

Commission staff argued that commodity component true-up costs are more appropriately included in the commodity cost component of the GCRM and that including it in the supply reservation cost component distorts price signals and the commodity cost component.

The Commission finds that it is reasonable for NSPW's proposal to include in the supply reservation cost component the following rates: supply reservation costs paid to supplier; storage capacity costs; and miscellaneous fixed cost pieces. The Commission also finds that Commission staff's position regarding the propane/city gate sales adjustment and the commodity component true-up pieces of the GCRM is reasonable. Therefore, city gate purchases shall be treated like any other commodity purchase, indexed at the benchmark and included in the commodity cost component of the GCRM. Propane purchases shall not flow through the GCRM at this time. The commodity component true-up shall be included in the commodity cost component of the GCRM.

### **The Transition Cost Adjustment Component**

The transition cost adjustment component includes various demand surcharges as well as direct bills for stranded supply contracts.

NSPW proposed a one-for-one recovery of these costs with an on-going true-up as is currently allowed in the PGA. NSPW had originally proposed moving these costs to the supply reservation component when the costs dropped to a certain level. NSPW modified their proposal and will discuss with Commission staff moving the costs at the point in the future when the costs drop to an insignificant level. Commission staff agreed with NSPW's proposal as modified.

The Commission finds that NSPW's transition cost adjustment component proposal to be reasonable as modified.

### **The Commodity Cost Component**

The commodity cost component includes all costs collected in the commodity component of the current PGA. The component would be priced monthly, at the benchmark. Over or under recoveries of actual costs determined to be prudent would be reconciled in a true-up. The component consists of three parts:

### **1. Variable Commodity and Transportation Costs**

Variable Commodity and Transportation Costs includes the commodity cost of gas purchased for system sales; monthly pipeline cash-outs; all volumetric transportation costs for system sales; fuel used in transportation for system sales; city gate purchases (this portion would be priced at the benchmark); and propane air costs (this portion would be priced at the benchmark).

### **2. Variable Storage Costs**

Variable Storage Costs includes storage withdrawals and withdrawal fees; and LNG withdrawals (no injection or withdrawal fees).

### **3. Miscellaneous Commodity Related Costs**

Miscellaneous Commodity Related Costs includes the cost of gas for company use; lost and unaccounted for gas; hedging instruments costs/losses/gains; and credits for monthly cash-out revenues.

NSPW proposed that if it used hedging instruments to lower risk and such usage did not increase costs over the benchmark, that those costs would be included in the commodity cost component of the GCRM. Commission staff concurred with NSPW's proposal regarding hedging instruments provided that NSPW agreed to follow the appropriate procedures and obtain Commission approval of a hedging program before flowing these costs through the GCRM.

The Commission finds it reasonable that the variable commodity and transportation piece of the commodity cost component be modified as previously discussed for city gate purchases and propane air costs. Therefore, the variable commodity and transportation costs shall include commodity cost of gas purchased for system sales, monthly pipeline cash-outs, all volumetric transportation costs for system sales, fuel used in transportation for system sales and city gate purchases. The Commission finds NSPW's proposal for the variable storage cost piece of the commodity cost component to be reasonable. Also, the Commission finds the miscellaneous commodity related cost piece to be reasonable as modified for hedging. The Commission finds that it is reasonable for NSPW to seek and obtain Commission approval of a hedging program before flowing the costs associated with using hedging instruments through this component of the GCRM. Hedging cost are only reasonable and may be recovered in the GCRM inclusive if they do not increase costs over the benchmark.

### **Determination of the Gas Commodity Price Benchmark for NSPW**

In the 106 Order, the Commission found that it is appropriate to use utility-specific gas commodity price benchmarks as a basis to judge the reasonableness of prices charged under a modified one-for-one GCRM. The Commission found that use of utility-specific commodity price benchmark would provide appropriate price signals to customers, lessen the monthly data filing requirements for estimating costs, and would correspondingly reduce regulatory review.

The commodity benchmark should be unique to each utility. The public indices would be weighted to reflect the various supply areas from which the utility purchases natural gas. The combined benchmark would be based on a utility's supply plan or purchasing practices assuming normal weather. The utility specific benchmark would be based on utility history and projections and would be used in the PGA for the monthly commodity cost of gas instead of the forecasted costs that had been used in the past.

The commodity cost component, as proposed, would include all costs collected in the commodity component of the current PGA. The component would be priced monthly, at the benchmark. Over and under recoveries of actual costs determined to be prudent would be reconciled in a true-up. NSPW proposed what it has termed a simple benchmark. The benchmark, as proposed, would use the average of Northern Natural Gas Company's (NNG) Ventura and Demarcation indices, plus NNG's variable transportation rate, plus fuel, adjusted for storage in the winter. NSPW argued that the intent of the 106 Order was to benchmark against the market as defined by market area indices. NSPW argued that market area indices provide appropriate price signals; do not unduly hinder workable markets; and facilitate its complicated transportation portfolio. NSPW further implied that use of supply area indices or indexing an LDC's unique contracts to itself, as Commission staff suggested, would result in a GCRM that is just like the current PGA.

Commission staff argued that for modified one-for-one GCRMs, the 106 Order contemplates a mechanism that closely resembles the current PGA, but with more extensive review of costs. Under a modified one-for-one GCRM, abnormal commodity costs should be identified and reviewed before any decision on recovery is made and that a sharing mechanism for opportunity sales could be incorporated. In a modified one-for-one gas cost recovery mechanism, it is critical that the indices used to develop the benchmark are reflective of the LDC's supply portfolio. The Commission reviews and approves the LDC's annual supply plan including the supply mix. A benchmark that is reflective of the approved supply portfolio monitors and highlights deviations for further Commission review. Commission staff argued that use of a benchmark that reflects the market rather than the LDC's supply portfolio would circumvent the process, hindering identification of significant deviations from the approved supply plan. Commission staff recommended that NSPW develop a benchmark using indices that are reflective of its current supply portfolio, if necessary weighing specific unique contracts to their contractual terms.

The Commission finds that Commission staff's position is reasonable. The intent of the 106 Order is clear: a modified one-for-one GCRM should utilize a benchmark that is reflective of a LDC's approved supply portfolio. This permits the Commission to develop a basis to judge the reasonableness of the gas costs and lessens the monthly data filing requirements for estimating costs and the corresponding regulatory review. The Commission finds it reasonable that NSPW develop a benchmark that is reflective of the Commission decision within 60 days from the effective date of this order.

### **Reconciliation of Commodity Costs**

NSPW had proposed an annual reconciliation arguing that a monthly reconciliation between the benchmark and the actual costs is too rigid. NSPW also argued that a monthly reconciliation did not fit well with NSPW's current supply portfolio and pricing diversity. Commission staff argued that the monthly reconciliation is required by the 106 Order for modified one-for-one GCRMs. Costs at or below the benchmark would receive little review and flow through the GCRM almost automatically. Costs above the benchmark would be reviewed and a decision would be made as to prudence. If the costs were found to be prudent, they could be recovered through the GCRM in the commodity true-up component. An annual true-up would subject the entire year's gas commodity costs to a prudence review. Under a modified one-for-one mechanism failure to review costs on a monthly basis could result in costs outside of the benchmark not receiving the appropriate regulatory review and in some instances receiving automatic recovery (i.e., costs over the benchmark in one month might be balanced against cost under the benchmark in another). Commission staff argued that there is a danger that a utility could price at the benchmark (when in reality actual cost are lower) and receive approval to collect more than the benchmark when costs are higher.

The Commission finds that Commission staff's position requiring the monthly reconciliation to be reasonable and consistent with the 106 Order.

### **Standard Reporting**

NSPW raised three issues in connection with standard reporting: 1) the Standardized Reporting Format tends to overstate revenues recovered because it does not recognize the imperfection of the revenue recovery under a billing system based on a revenue-month cycle; 2) the Standardized Reporting Format will be used as a means by which a modified one-for-one GCRM will receive a prudence review; and 3) the current standard reporting format does not contemplate a commodity cost true-up. Commission staff stated that they would work with NSPW to correct any formatting problems with the Standardized Reporting Format. Commission staff clarified that a GCRM prudence review will look at actual cost compared to the benchmark. Therefore, the standardized report will not trigger a GCRM prudence review.

The Commission directed Commission staff to work with NSPW to address its concerns regarding the Standardized Reporting Format.

### **Environmental Impact**

NSPW's proposal to increase electric rates and decrease natural gas rates is a Type III action under s. PSC 4.10(3), Wis. Adm. Code. No unusual circumstances suggesting the likelihood of significant environmental consequences have come to the Commission's attention. Neither an environmental impact statement under s. 1.11, Stats., nor an environmental assessment is required.

**Effective Date**

The Commission finds it reasonable that the effective date of this order be the day after the order is mailed. Rates shall take effect on the date they are filed in all of NSPW's offices and pay stations.

**ULTIMATE FINDINGS OF FACT**

**THE COMMISSION FINDS:**

1. At present rates, it is reasonable to estimate NSPW's Wisconsin retail electric operating income at \$42,088,000 and retail gas operating income at \$7,979,000 for the test year ending December 31, 1998.
2. The estimated average net investment rate base applicable to retail electric and gas utility operations for the test year ending December 31, 1998 is \$453,023,000 and \$64,821,000, respectively.
3. The pro forma rates of return on average net investment rate base at present rates for electric and gas utility operations for the test year ending December 31, 1998, are 9.29 and 12.31 percent, respectively.
4. A reasonable utility capital structure for the test year consists of 54.996 percent common equity, 38.739 percent long-term debt, and 6.265 percent short-term debt. An appropriate long-term common equity ratio range for Applicant continues to be 52 to 57 percent.
5. A return on common stock equity of 11.9 percent is just and reasonable for NSPW.
6. A just and reasonable short-term debt rate is 5.763 percent.
7. NSPW's ten-year financial forecast is useful in assessing the reasonableness of its capital structure and the required return on equity.
8. Returns on rate base of 10.25 and 10.52 percent for electric and gas utility operations, respectively, are just and reasonable.
9. NSPW's operating revenue requirement for retail electric utility operations for the test year ending December 31, 1998, to produce a return of 10.25 percent on average net investment rate base, is approximately \$298,938,000.

10. Presently authorized rates for electric utility service will produce Wisconsin retail operating revenues of approximately \$291,682,000 for the 1998 test year, which is \$7,256,000 less than the required level.

11. NSPW's operating revenue requirement for retail gas utility operations for the test year ending December 31, 1998, to produce a return of 10.52 percent on average net investment rate base, is approximately \$87,205,000.

12. Presently authorized rates for gas utility service will produce Wisconsin retail operating revenues of approximately \$89,141,000 for the 1998 test year, which is \$1,936,000 more than the required level.

13. NSPW's allowed conservation and safety advertisements, advertisements required by law, and general information advertisements provide a direct and substantial benefit to its ratepayers.

14. Conservation budgets of \$4,380,600 and \$1,628,017 for retail electric and gas utility operations, respectively, are just and reasonable for NSPW in the test year ending December 31, 1998.

15. A reasonable estimate of total test year gas sales and other revenues is \$89,580,000.

16. The additional amount of revenue requirement for NSPW in connection with NSPM's acquisition of the Viking Gas Transmission Company should be reduced to \$210,000 to accommodate the biennial rate case process. In addition, the reporting requirement relating to the economic benefit of Viking to NSPW's customers may be discontinued.

17. Revenues from area expansion program surcharges should be recorded as contributions to the cost of construction and, ultimately, as credits to plant-in-service.

18. A reasonable estimated fuel cost for the test year, plus the cost of purchased energy, wheeling and capacity, less the revenue from external sales of energy and capacity, is \$526,533,576 for 39,862,925 MWh, or \$0.01321 per kWh. These amounts include the total NSP system native energy requirements and costs to arrive at fuel cost data. The Commission finds that method to be appropriate in view of the Applicant's interchange agreement with NSPM. A reasonable estimate of fuel costs for each month of the test year is attached as Appendix D. That schedule will be used for required monthly monitoring of fuel cost.

19. NSP will continue to need utility employees that actively participate in the wholesale bulk power market for the marketing of excess capacity.

20. It is reasonable and appropriate to eliminate the natural gas sales promotion budget for 1998 and 1999.

21. The 1998 total company natural gas DSM goal of 1,579,155 therms (gross) and the associated minimum sector therm targets as described in the Findings of Fact are reasonable and appropriate. Further, it is reasonable and appropriate to further reduce the 1999 company gas goal and associated minimum sector therm targets as described in the Findings of Fact if NSPW develops detailed program descriptions and an evaluation plan for its market preparation activities in 1999.

22. Total Company electric DSM goals of 48.0 GWh, with a low-income goal of 564,775 kWh, for 1998 and 1999, are reasonable and appropriate.

23. It is reasonable and appropriate to re-establish a residential sector electric DSM goal of 12.4 GWh for NSPW for each of 1998 and 1999.

24. It is reasonable and appropriate to increase NSPW's annual low-income budget by \$101,816, to a total of \$405,000 for 1998 and 1999. Further, it is reasonable and appropriate for NSPW to follow the transitional and funding guidelines for utility low-income energy efficiency programs as described in the Findings of Fact.

25. The rate changes set forth in Appendices B and C for retail electric and natural gas service will permit Applicant to earn the necessary operating revenue requirement, are consistent with the previous Findings of Fact relating to rate design and cost-of-service, and are just and reasonable.

26. Expanding the availability of the Cg-6 rate to residential and farm customers and increasing the off-peak time period for this rate, as set forth in Appendix B, is reasonable.

27. Changing the power factor provision for the Cp-1 and Cp-2 tariffs and changing the minimum power factor requirement for the Mp-1 rate class to 90 percent, as set forth in Appendix B, is reasonable.

28. Changing the language of the processing charge provision to require a charge of \$16.50 be applied in cases where a landlord does not want the electric or gas service put in his/her name during the time between tenants and requests NSPW lock the meter, as set forth in Appendix B, is reasonable.

29. Renaming the Customer Demand Charge to Distribution Demand Charge and other changes to the electric tariff language, as set forth in Appendix B, is reasonable.

30. The Pg-2, standard parallel generation buy-back rates and the Pg-2.2 hydroelectric energy purchase service rates, set forth in Appendix B, are reasonable.

31. Extending the experimental time period, for the Real-Time Pricing (RTP-1) rate, to December 31, 1999, is reasonable.

32. It is reasonable to require NSPW to change the availability clause for the Rg-2, Residential Time-of-Day Service, tariff to require all residential customers with annual usage greater than 60,000 kWh to be billed on the Rg-2 rate.

33. It is reasonable to increase the customer charges of the Group 3, 4 and 5 Ig-1 Interruptible service customer classes.

34. It is reasonable to remove costs related to gas supply purchasing personnel, the cost of peaking plants, the carrying cost of gas and the portion of gross receipts tax paid on gas sales revenues from the distribution service rates.

35. It is reasonable to recover the gas supply costs removed from the distribution service rates on a per therm basis from system sales customers.

36. It is reasonable for NSPW and Commission staff to work together to develop an appropriate billing format for natural gas customer bills.

37. It is reasonable to add clarifying incremental cost language to the unauthorized use penalty provision.

38. It is reasonable to change the basis for calculation of incidental use to provide for more timely billing of unauthorized use of natural gas.

39. It is reasonable to add language clarifying priority of service due to supply and capacity situations that may vary across the NSPW system.

40. It is reasonable to require telemetering for Ig-1 interruptible customers and Lg-1 partially interruptible customers to assure customer compliance with interruption and curtailment orders.

41. It is reasonable to shorten the notification period for customers that chose to move between gas supply schedules.

42. It is reasonable to offer GMS to interruptible distribution customers as a customer service option at this time. However, the appropriateness of continuing GMS in its current form will be reexamined in NSPW's next rate case.

43. The capacity release/opportunity sales revenue credit shall include opportunity sales as defined by the Commission in the order in docket 05-GI-108, Phase II and as clarified in this docket. This definition will encompass swaps that involve unused and underutilized assets held for system use. Swaps that utilize a mixture of used and unused assets will be excluded.

Revenues from interruptible flex-up and GMS tariffs will not be included as opportunity sales and will not be subject to the sharing mechanism.

44. Opportunity sales subject to the sharing mechanism shall be those sales in excess of the target level. The target level for capacity release/opportunity sales volume for each month shall be based on the level of capacity above the design day for that month, as identified in NSPW's approved supply plan.

45. It is reasonable that the capacity release/opportunity sales revenues available for sharing should be shared with 75 percent of the revenues accruing to the ratepayers and 25 percent of the revenues accruing to the shareholders. It is reasonable that the capacity release/opportunity sales revenues not available for sharing (capacity above the monthly design day) be credited 100 percent to the ratepayers.

46. It is reasonable that city gate purchases shall be treated like any other commodity purchase, indexed at the benchmark and included in the commodity cost component of the GCRM. It is reasonable that propane purchases shall not flow through the GCRM at this time.

47. It is reasonable that the commodity component true-up shall be included in the commodity cost component of the GCRM.

48. It is reasonable that the variable commodity and transportation piece of the commodity cost component include commodity cost of gas purchased for system sales, monthly pipeline cash-puts, all volumetric transportation costs for system sales, fuel used in transportation for system sales and city gate purchases.

49. It is reasonable that NSPW seek and obtain Commission approval of a hedging program before flowing the costs associated with hedging instruments through the GCRM.

50. It is reasonable that NSPW develop a benchmark that is reflective of its approved supply portfolio within 60 days from the effective date of this order.

51. It is reasonable that a monthly reconciliation be required.

52. It is reasonable that NSPW and commission staff work together to address NSPW's concerns regarding the Standardized Reporting Format.

## CONCLUSIONS OF LAW

### THE COMMISSION CONCLUDES THAT:

It has jurisdiction under ss. 1.11, 1.12, 196.03, 196.20, 196.37, 196.374 and 196.395, Stats., and s. PSC 116.06, Wis. Adm. Code, to enter an order authorizing NSPW to place into effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, subject to the conditions specified in this order, and that such rates and rules are just and reasonable.

### ORDER

### THE COMMISSION THEREFORE ORDERS THAT:

1. The effective date of this order shall be one day after the date of mailing to the parties in this proceeding. The authorized electric and gas rates and rules shall be effective on that date, provided that the rates and rules are filed with the Commission and placed in all offices and stations of the utility by that date in accordance with ss. 196.21 and 196.40, Stats. If the authorized rates and rules are not placed in all offices and stations prior to that date, the rates and rules will become effective on the date the rates and rules are placed in all offices and stations. The utility shall file tariff sheets with the Commission, which reflect the authorized rates and rules.
2. NSPW's retail electric and gas conservation budgets for the test year ending December 31, 1998, shall be \$4,380,600 and \$1,628,017, respectively.
3. NSPW shall submit a ten-year financial forecast in its next rate filing before this Commission.
4. Revenues from area expansion program surcharges should be recorded as contributions to the cost of construction and, ultimately, as credits to plant-in-service.
5. A reasonable estimated fuel cost for the test year, plus the cost of purchased energy, wheeling and capacity, less the revenue from external sales of energy and capacity, is \$526,533,576 for 39,862,925 MWh, or \$0.01321 per kWh. The fuel costs estimated in Appendix D shall be used for required monthly monitoring of fuel cost.
6. NSPW shall adopt the 1998 and total company electric DSM goals, electric low-income goals, and electric residential goals, as described in the Findings of Fact. NSPW shall also adopt the 1998 and 1999 total company natural gas DSM goals, gas low-income goals, and gas sector minimum targets, as described in the Findings of Fact.

7. NSPW shall adopt the transitional funding and delivery guidelines for utility low-income energy efficiency programs as described in the Findings of Fact.

8. NSPW shall substitute, for its existing rates and rules for retail electric and natural gas service, the rate and rule changes contained in Appendices B and C.

9. NSPW shall prepare bill inserts appropriately identifying the monthly rates, rate schedule changes, and rules specified in Appendices B and C. NSPW shall distribute these inserts to customers with the first billing containing these rates. NSPW shall file a copy of these inserts with the Commission.

10. NSPW shall work with Commission staff to develop an appropriate billing format for customer natural gas bills. The final language shall be approved by Commission staff and shall be implemented by October 1, 1999.

11. The appropriateness of continuing GMS in its current form will be reexamined in NSPW's next rate case.

12. The capacity release/opportunity sales revenue credit shall include opportunity sales as defined by the Commission in the order in docket 05-GI-108, Phase II and clarified in this docket. This definition will encompass swaps that involve unused and underutilized assets held for system use. Swaps that utilize a mixture of used and unused assets will be excluded. Revenues from interruptible flex-up and GMS tariffs will not be included as opportunity sales and will not be subject to the sharing mechanism.

13. That opportunity sales subject to the sharing mechanism shall be those sales in excess of the target level. The target level for capacity release/opportunity sales volume for each month shall be based on the level of capacity above the design day for that month, as identified in NSPW's approved supply plan.

14. The capacity release/opportunity sales revenues available for sharing should be shared with 75 percent of the revenues accruing to the ratepayers and 25 percent of the revenues accruing to the shareholders. The capacity release/opportunity sales revenues not available for sharing (capacity above the monthly design day) shall be credited 100 percent to the ratepayers.

15. City gate purchases shall be treated like any other commodity purchase, indexed at the benchmark and included in the commodity cost component of the GCRM. Propane purchases shall not flow through the GCRM at this time.

16. The commodity component true-up shall be included in the commodity cost component of the GCRM.

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17. The variable commodity and transportation piece of the commodity cost component shall include commodity cost of gas purchased for system sales, monthly pipeline cash-puts, all volumetric transportation costs for system sales, fuel used in transportation of system sales and city gate purchases.

18. NSPW shall seek and obtain Commission approval of a hedging program before flowing the costs associated with hedging instruments through the GCRM.

19. NSPW shall develop a benchmark that is reflective of its approved supply portfolio within 60 days from the effective date of this order.

20. A monthly reconciliation shall be required.

21. NSPW and Commission staff shall work together to address NSPW's concerns regarding the gas Standardized Reporting Format.

22. Jurisdiction is retained.

Dated at Madison, Wisconsin, \_\_\_\_\_

By the Commission:

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Lynda L. Dorr  
Secretary to the Commission

LLD:LMS:RK:mem:G:\Order\Pending\4220-UR-110

See attached Notice of Appeal Rights

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in s. 227.53, Stats. The petition must be filed within 30 days after the date of mailing of this decision. That date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in s. 227.01(3), Stats., a person aggrieved by the order has the further right to file one petition for rehearing as provided in s. 227.49, Stats. The petition must be filed within 20 days of the date of mailing of this decision.

If this decision is an order after rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not an option.

This general notice is for the purpose of ensuring compliance with s. 227.48(2), Stats., and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

Revised 4/22/91

APPENDIX A  
(CONTESTED)

In order to comply with s. 227.47, Stats., the following parties who appeared before the agency are considered parties for purposes of review under s. 227.53, Stats.

Public Service Commission of Wisconsin  
(Not a party but must be served)  
610 N. Whitney Way  
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NORTHERN STATES POWER COMPANY

by

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WISCONSIN PAPER COUNCIL

by

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ENERGY MARKETERS ASSOCIATION OF WISCONSIN

by

Mr. John L. Walker  
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WISCONSIN POWER AND LIGHT COMPANY

by

Mr. Terry Nicolai  
Manager of Regulatory Relations  
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WISCONSIN PUBLIC SERVICE CORPORATION

by

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SELECT ENERGY CONSULTING

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by

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CITY OF LACROSSE

By

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