KC, DJ [illegible] to KC, DJ, MC, NK
BB, NB, K[illegible] NG99-002

DOCKET NO. NG99-002

In the Matter of IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE

Public Utilities Commission of the State of South Dakota

DATE	MEMORANDA
6/1/99	Filed and Docketed;
6/3/99	Weekly Filing;
6/25/99	Order of Assessment of Filing Fee, Notice of Opportunity to Intervene,
8/3/99	Order for and Notice of Hearing;
8/16/99	Contract between Cheseapeke Regulatory Consultants Inc and SDPUC;
9/7/99	Petition to Extend Suspension of Imposition of Tariff;
9/14/99	Order Extending Suspension of Imposition of Tariff;
9/24/99	Testimony and Exhibits of David A Jacobson;
9/24/99	Testimony of Marlin C Bettmann;
9/24/99	Testimony and Exhibits of Thedric Th Ferris;
9/24/99	Testimony and Exhibits of Keith A Jorgensen;
9/24/99	Testimony and Exhibit of Basil L Copland Jr;
9/24/99	Testimony of Robert L Towers;
10/8/99	Request for Suspension of Procedural Schedule;
10/12/99	Amended Order for and Notice of Hearing;
10/13/99	Rebuttal Testimony of James P Nitschke;
10/13/99	Rebuttal Testimony of Nicholas J Hanson;
10/19/99	Settlement Agreement between NPS and Commission Staff;
10/21/99	Additional Testimony of David A Jacobson;
10/27/99	Transcript of Settlement Held on 10/20/99;
10/27/99	Transcript of Contested Case Held on 10/20/99;
11/8/99	Tariff Schedules;
11/15/99	Decision and Order Approving Settlement Agreement;

(over)

STATE PUBLISHING CO., PIERRE, SOUTH DAKOTA

11/30/99	Affidavits Contracts Pursuant to Settlement Agreements
11/30/99	Initial Brief of NWPS;
12/8/99	Order Approving Staff Testimony;
1/7/00	Brief of Commission Staff;
1/12/00	Late Filed Exhibits;
1/24/00	Rebuttal Brief of NWPS;
4/27/00	Find. of Fact and Con. of Law; Notice of Entry of Order
4/27/00	Docket Closed.
6/8/00	Motion to Compel NWPS to Comply with Commission Order
6/26/00	Response to Motion to Compel and Request for Clarification
12/6/00	Memorandum of NWPS Concerning Status of Rate Phase-In Pipeline
1/29/01	Order Granting in Part and Denying in Part Motion to Compel
2/14/01	Firm Transportation Service Agreement (Agreement filed as Document No. 010210-EG)
5/11/01	Order Finding Pipeline is not an Interstate Natural Gas Pipeline
5/11/01	Docket Closed.

NG99-002

RECEIVED

JUN 0 1 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STATE OF SOUTH DAKOTA

BEFORE THE

PUBLIC UTILITIES COMMISSION

In the matter of:
NORTHWESTERN PUBLIC SERVICE
a division of NorthWestern Corporation, Applicant) Docket No. NG99-___

Application of NorthWestern Public Service a division of NorthWestern Corporation

For Increased Natural Gas Rates

December 31, 1998 Test Year

Data Filed Pursuant to

Public Utilities Rate Filing Rules

Chapter 20:10:13

Original

NorthWestern

NorthWestern
PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney
Telephone 605 [illegible]
Facsimile 605 [illegible]
rmolstad@northwestern.com

May 28, 1999

Mr. William Bullard, Jr.
Executive Secretary
S. D. Public Utilities Commission
500 East Capitol Ave
Pierre SD 57501

Re: NorthWestern Public Service
Application for Authority to Increase Gas Rates

Dear Mr. Bullard

Enclosed you will find for filing 12 sets of Volumes I and II consisting of NorthWestern's rate application and accompanying testimony and exhibits together with a separate confidential envelope.

Included with this filing are revised natural gas rate schedules of NorthWestern Public Service. These schedules are designed to produce an additional $2,108,112 in revenues applicable to the NorthWestern South Dakota service area.

Also included are all supporting schedules required by Commission Rules and the prefiled direct testimony and exhibits of supporting witnesses.

NorthWestern will notify customers of the proposed increase by posting the enclosed Notice of Change in Rates at all of its business offices. NorthWestern will also file a press release concurrently with the filing of the application for rate increase. NorthWestern will notify customers in person after conclusion of this proceeding by mailing to them notices advising them of the final Commission approved rates.

According to its Rule 20:10:01:39-42, NorthWestern requests that the enclosed information be designated as **confidential** in Commission files. In accordance with Rule 20:10:01:41, the following information regarding this request is provided:

(1) Description of Information: Statement P - required by Rule 20:10:13:100. Cost of gas adjustment clause.

(2) Length of Time: Fifteen (15) years

(3) Identification of Contract Person: Russell C. Molstad, Jr.
Corporate Attorney
600 Market Street W
Huron, SD 57350

The grounds upon which confidential treatment is sought are Sections 4 and 5 of Rule 20:10:01:39. Confidential information (12 copies) is enclosed and marked (CONFIDENTIAL)

We request that communications to the Petition concerning this application be directed to:

Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service
600 Market Street W
Huron, SD 57350

Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street SE
Huron, SD 57350

One complete set of the filing has been marked "File Stamp Copy". Please stamp and return this set. We have returned enclosed postage for your convenience.

Sincerely yours,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures

NorthWestern Public Service

NOTICE OF PROPOSED CHANGE IN GAS RATES

In compliance with the regulations of the South Dakota Public Utilities Commission, NorthWestern Public Service hereby gives notice to its customers that on June 1, 1999, the Company filed with the Commission an Application for an increase in rates for gas service. The change in rates is proposed to become effective July 1, 1999.

Under South Dakota law, the Commission may suspend the implementation of the proposed rates pending its decision. The Company cannot implement a suspended rate for a period of six months after the date of filing of the Application. South Dakota law gives the Company's customers the right to join with 24 other customers and file a written objection with the Commission asking that it suspend the rates and hold a public hearing to determine whether the increase should be allowed.

A copy of the proposed schedule of gas rates in available in this office for inspection by customers of NorthWestern Public Service. If you would like to review the proposed schedule of rates, please ask any of the Company's office personnel for assistance.

Michael J. Hanson
President & CEO
NorthWestern Public Service

Exhibit ___ (DAM-1)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN RE:)	
NORTHWESTERN PUBLIC SERVICE,)	**Docket No. NG99-_____**
a division of NorthWestern Corporation)	

AFFIDAVIT OF DAVID A. MONAGHAN

STATE OF SOUTH DAKOTA)
COUNTY OF MINNEHAHA) SS

David A. Monaghan, being first duly sworn, deposes and says:

(1) He is the Controller and Treasurer of NorthWestern Corporation ("NorthWestern"), and in such capacity serves as its Chief Accounting Officer;

(2) As such Chief Accounting Officer, he has responsibility for all accounting records of NorthWestern, including its utility division NorthWestern Public Service;

(3) He has reviewed all cost statements, working papers, and other supporting data submitted as part of this filing or maintained by NorthWestern and NorthWestern Public Service, and such cost statements, working papers, and other supporting data accurately set forth the books of NorthWestern and NorthWestern Public Service

David A. Monaghan

Subscribed and sworn to this 27th day of May, 1999.

Notary Public, South Dakota
My Commission Expires: 3/6/2001

(Notary Seal)

NorthWestern Public Service Company
South Dakota Gas Rate Case
Report of Tariff Schedule Change
Test Year Ending December 31, 1998

Name of Utility:	NorthWestern Public Service
Utility Address:	600 Market Street West Huron, SD 57350
Description of Change:	General Rate Increase
Reason for Change:	Revenue Deficiency
Proposed Effective Date of Modified Rate:	July 1, 1999
Approximate Annual Change in Revenue	
Residential	$1,285,687
Small Commercial	494,413
Large Commercial	75,843
Interruptible	54,922
Transport	197,247
	$2,108,112
Communities Affected:	All South Dakota Communities served by NorthWestern Public Service
Approximate Number of Customers Affected:	
Residential	33,404
Small Commercial	4,907
Large Commercial	166
Interruptible	115
Transport	78
	38,670
Present Rate:	$33,657,074
Proposed Rate:	$35,765,186
Approximate Annual Increase in Revenue:	$2,108,112
Number of Customers Whose Cost of Service will be Affected:	All South Dakota Natural Gas Customers

Submitted by: Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 2
Pro Forma — Sheet No. 1
Canceling — Sheet No. 1

PRELIMINARY STATEMENT

Territory Served

Northwestern Public Service Company ("Company") provides gas service at retail to the following communities and their immediate environs in eastern South Dakota.

Aberdeen	Dimock	Lake Norden	Redfield
Alexandria	Doland	Lake Preston	Revillo
Altamont	Estelline	Madison	Scotland
Arlington	Ethan	Marion	Spencer
Aurora	Ferney	Mellette (N)	Tripp
Big Stone City	Frankfort	Menno	Turton
Bristol	Goodwin	Milbank	Verdon
Brookings	Groton	Mitchell	Vienna
Bryant	Hayti (N)	Monroe	Volga
Canistota	Hazel	Mt. Vernon	Warner
Castlewood	Holmquist	Oldham	Webster
Clark	Howard	Olivet	Willow Lake
Clear Lake	Huron	Parker	Wolsey (N)
Conde	Kranzburg	Parkston	Yale
DeSmet	Labolt	Raymond	

A map showing communities served with gas service at retail follows this sheet.

Types and Classes of Service

1. Residential Gas Service
2. General Gas Service
3. Commercial and Industrial Firm Sales Service
4. Commercial and Industrial Interruptible Sales Service
5. Transportation Service, including Customer Balancing and Standby Service Options

All service is furnished under the provisions of the Company's General Terms and Conditions set forth in Section No. 5 of these tariff schedules.

(continued)

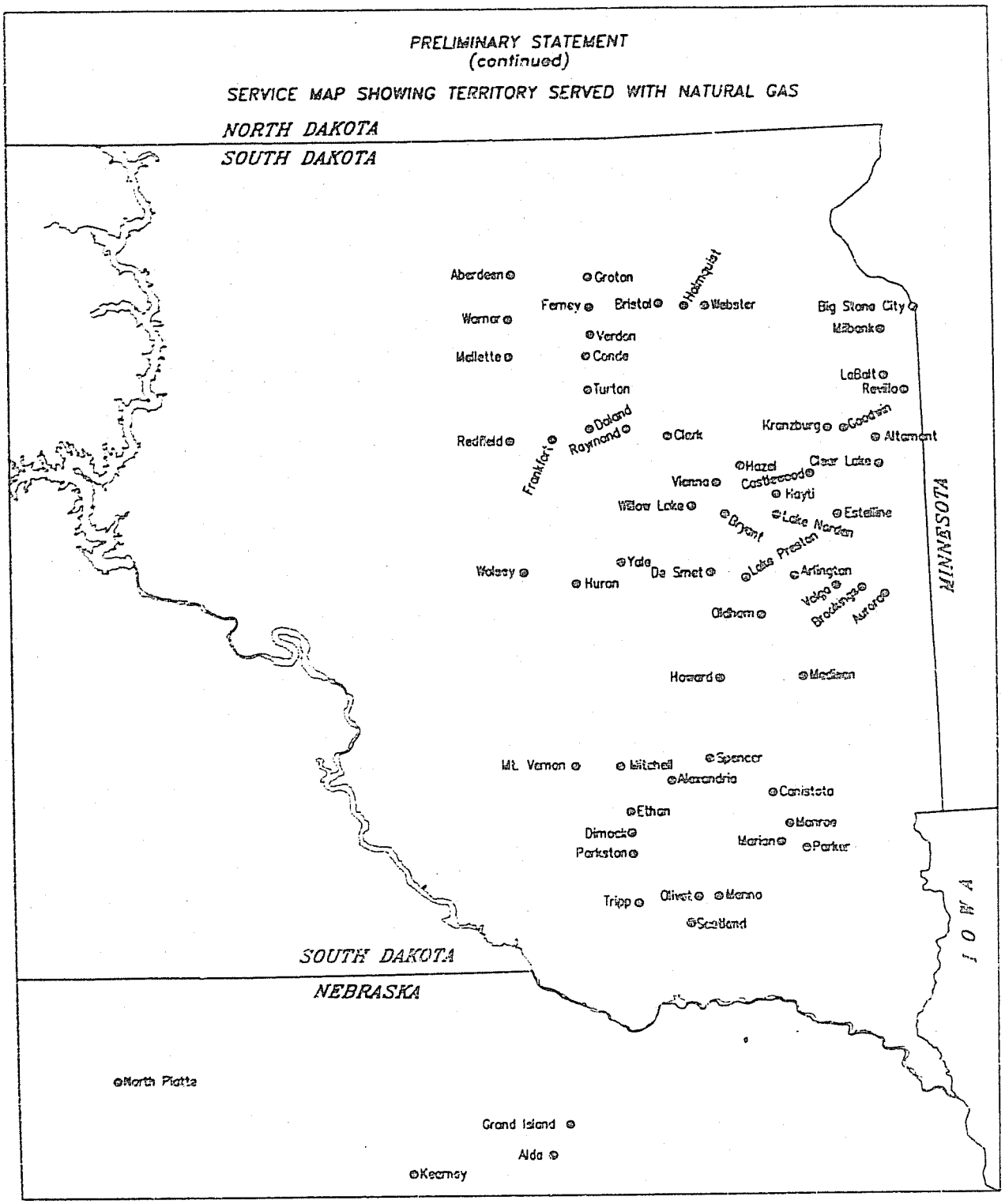
SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 2
Pro Forma — Sheet No. 2
Canceling _____ Sheet No. 2

PRELIMINARY STATEMENT
(continued)

SERVICE MAP SHOWING TERRITORY SERVED WITH NATURAL GAS



(N)

(N)

Date Filed: June 1, 1999

Effective Date: July 1, 1999

Michael J. Hanson

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
Pro Forma — Sheet No. 1
Canceling _____ Sheet No. 1

CLASS OF SERVICE: Residential Gas Service — Rate No. 81
RATE DESIGNATION: Firm Sales

1. **Applicability**
This rate is available to domestic customers whose maximum requirements for natural gas are not more than 200 therms per day. The name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements, based on 10 hours use per day.

2. **Territory**
The area served with natural gas by the Company in South Dakota.

3. **Rates**

Monthly Charges:			
Customer Charge per Meter:	$	6.00	(I)
Non-Gas Commodity Charge:			
First 30 therms, per therm	$	0.2474	(I)
Over 30 therms, per therm	$	0.1320	(I)
Standby Capacity Charge - December through March:	$	12.00	
Minimum Monthly Bill:	$	6.00	(I)

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. **Other Provisions**
The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: June 1, 1999
Service on and after
Effective Date: July 1, 1999

Michael J. Hanson
Issued By: President & CEO

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
Pro Forma — Sheet No. 2
Canceling _____ Sheet No. 2

CLASS OF SERVICE: General Gas Service — Rate No. 82
RATE DESIGNATION: Firm Sales

1. **Applicability**

This rate is available to non-residential customers whose maximum requirements for natural gas are not more than 200 therms per day. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements.

2. **Territory**

The area served with natural gas by the Company in South Dakota.

3. **Rates**

Monthly Charges:

Customer Charge per Meter:	$	7.00	(I)
Non-Gas Commodity Charge:			
First 400 therms, per therm	$	0.1471	(I)
Next 1,600 therms, per therm	$	0.0941	(I)
Over 2,000 therms, per therm	$	0.0591	(I)
Standby Capacity Charge - December through March:	$	37.00	
Minimum Monthly Bill:	$	7.00	(I)

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. **Other Provisions**

The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: June 1, 1999

Service on and after
Effective Date: July 1, 1999

Michael J. Hanson
Issued By: President & CEO

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
Pro Forma Sheet No. 3.1
Canceling Sheet No. 3.1

CLASS OF SERVICE: Commercial and Industrial Rate No. 84
RATE DESIGNATION: Firm Sales Service

1. **Applicability**

This rate is available for firm gas volumes, on a contract basis, to commercial and industrial customers whose maximum requirements for natural gas are greater than 200 therms per day, and who may also require volumes of interruptible gas in excess of firm demand volumes for which they have contracted. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirement.

2. **Territory**

The area served with natural gas by the Company in South Dakota.

3. **Rates**

Customer may choose the rate option, and level of daily contract demand (never less than 50 therms), which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$ 80.00	$280.00	(I)
Non-Gas Commodity Charge, all use, per therm:	$0.0462	$0.0225	(I)
Demand Charge per therm of daily contract demand as shown on Sheet 9a.			

Gas Demand Payment Elections

A. Annually - in advance, with 5% discount
B. Seasonally profiled

January & February	20% of annual charge per month
March & December	15% of annual charge per month
April & November	10% of annual charge per month
May & October	5% of annual charge per month
June through September	0% of annual charge per month

C. Monthly - 12 equal billings

In the absence of an appropriate election by customer Election "C" will be automatically assigned. Unless otherwise mutually agreed upon between the Company and customer all elections must be for a minimum period of twelve consecutive months.

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
Pro Forma Sheet No. 4.1
Canceling Sheet No. 4.1

CLASS OF SERVICE: Commercial and Industrial Rate No. 85
RATE DESIGNATION: Interruptible Sales Service

1. **Applicability**

Gas service under this rate schedule is available on an interruptible basis to any customer for commercial and industrial purposes, whose maximum requirements for natural gas are greater than 200 therms per day, provided that the customer's premises are adjacent to the Company's mains and that the capability of the Company's system and the supply of gas available from its suppliers is in excess of the requirements of its existing customers. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirement.

2. **Territory**

The area served with natural gas by the Company in South Dakota.

3. **Rates**

Customer may choose the rate option which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$ 80.00	$280.00	(I)
Non-Gas Commodity Charge, all use, per therm:	$0.0462	$0.0225	(I)

Minimum Monthly Bill:
The Customer Charge.

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. **Penalty Provision**

If customer fails to comply with Company's request to curtail the use of gas, then all unauthorized gas so used shall be "Penalty Gas" and be paid by the Customer at a rate which is the greater of $3.00 per therm or the maximum penalty charges permitted to be made by the Company's upstream service providers for takes of natural gas in addition to the regular Commodity Charge for such gas. All costs collected will be credited to expense in PGA true-up filings.

Date Filed: June 1, 1999
Service on and after
Effective Date: July 1, 1999

Michael J. Hanson
Issued By: President & CEO

CLASS OF SERVICE: Gas Transportation Tariffs Rate No. 87
RATE DESIGNATION: Transportation Service

1. **Applicability and Character of Service**
This Transportation Service Tariff shall apply to gas purchased by Customer from a third-party supplier, or through an agency relationship with the Company, delivered to Company's system by an interstate pipeline, and received, transported, and delivered, on a firm basis, by Company to Customer's premises, when the Company and Customer have executed a Service Request Form.

2. **Availability**
This service is available to any Customer with facilities served by the Company in South Dakota who has Company installed telemetric equipment in place to monitor daily usage. Company shall have no obligation to provide gas supplies to customers that contract for this service without also contracting for Firm Supply Standby Service or other optional firm supply services that may be offered. In the event that a Customer seeks to purchase gas supplies from Company, such sales shall be at the sole discretion of Company.

3. **Rates**
Customer may choose the rate option which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$130.00	$330.00	(I)
Commodity Charge, all use, per therm:	$0.0462	$0.0225	(I)

Fuel Retention, a Customer or Group Customer, if applicable, shall have the option to choose either an indexed based or inkind method to apply retention, as provided in the Gas Transportation General Terms and Conditions in Section No. 5 of this tariff.

One-Time Charges:

Application Charge:	$50.00 with each request for service.
Telemetering:	Standard cost of telemetry, installation and hardware, including appropriate tax gross-up, shall be $2.100 per unit installed.

Minimum Monthly Bill:
The Customer Charge.

Statement A

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	428,950,557	435,593,765
3	Construction Work in Progress (107)	200-201	12,529,151	15,704,915
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		441,479,708	451,298,680
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	171,808,953	181,107,119
6	Net Utility Plant (Enter Total of line 4 less 5)		269,670,755	270,191,561
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		269,670,755	270,191,561
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	0	0
15	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	80,709,504	93,820,396
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		590,403	506,765
21	Special Funds (125-128)		0	0
22	TOTAL Other Property and Investments (Total of lines 14 thru 17,19,21)		81,299,907	94,327,161
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)		3,749,599	979,323
25	Special Deposits (132-134)		0	0
26	Working Fund (135)		28,581	32,351
27	Temporary Cash Investments (136)		0	3,063,122
28	Notes Receivable (141)		0	0
29	Customer Accounts Receivable (142)		10,840,772	11,670,642
30	Other Accounts Receivable (143)		6,000,068	3,9,157
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		500,000	400,000
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		32,772,127	276,772,044
34	Fuel Stock (151)	227	1,830,197	1,979,19[illegible]
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products	227	0	0
37	Plant Materials and Operating Supplies (154)	227	3,878,027	3,562,051
38	Merchandise (155)	227	222,395	22,910
39	Other Materials and Supplies (156)	227	183,884	183,884
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	755,112	1,313,196
44	Gas Stored Underground - Current (164.1)		1,753,789	2,056,392
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		5,849,135	6,777,487
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		0	0
49	Rents Receivable (172)		0	0
50	Accrued Utility Revenues (173)		3,085,959	3,648,805
51	Miscellaneous Current and Accrued Assets (174)		3,404,573	5,588,751
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		73,854,318	317,589,312

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)		1,860,377	14,763,341
55	Extraordinary Property Losses (182.1)	230	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
57	Other Regulatory Assets (182.3)	232	0	0
58	Prelim. Survey and Investigation Charges (Electric) (183)		444,354	444,354
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
60	Clearing Accounts (184)		504,927	1,198,582
61	Temporary Facilities (185)		0	0
62	Miscellaneous Deferred Debits (186)	233	13,499,848	15,536,544
63	Def. Losses from Disposition of Utility Plt. (187)		0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reaquired Debt (189)		1,760,765	1,662,198
66	Accumulated Deferred Income Taxes (190)	234	0	0
67	Unrecovered Purchased Gas Costs (191)		3,789,453	3,868,646
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		21,859,724	37,473,665
69	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,52,68)		446,584,704	719,581,699

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	31,224,417	40,279,474
3	Preferred Stock Issued (204)	250-251	3,750,000	3,750,000
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	56,590,924	158,529,650
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	45,550,146	42,825,029
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	27,365,095	38,274,957
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		164,480,582	283,659,110
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	140,000,000	240,000,000
17	(Less) Reaquired Bonds (222)	256-257	0	0
18	Advances from Associated Companies (223)	256-257	0	0
19	Other Long-Term Debt (224)	256-257	54,855,154	111,556,184
20	Unamortized Premium on Long-Term Debt (225)		0	0
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		194,855,154	351,556,184
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)		0	0
25	Accumulated Provision for Property Insurance (228.1)		0	0
26	Accumulated Provision for Injuries and Damages (228.2)		349,232	350,000
27	Accumulated Provision for Pensions and Benefits (228.3)		126,005	315,965
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
29	Accumulated Provision for Rate Refunds (229)		0	0
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		475,237	665,965
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)		0	0
33	Accounts Payable (232)		8,755,941	8,923,982
34	Notes Payable to Associated Companies (233)		0	0
35	Accounts Payable to Associated Companies (234)		4,461,781	6,558,433
36	Customer Deposits (235)		415,783	305,720
37	Taxes Accrued (236)	262-263	8,142,094	6,128,372
38	Interest Accrued (237)		4,017,823	5,011,486
39	Dividends Declared (238)		0	0
40	Matured Long-Term Debt (239)		0	0
41	Matured Interest (240)		0	0
42	Tax Collections Payable (241)		1,092,297	660,206
43	Miscellaneous Current and Accrued Liabilities (242)		2,774,800	4,683,503
44	Obligations Under Capital Leases-Current (243)		0	0
45	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		29,660,519	32,271,707

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		0	0
48	Accumulated Deferred Investment Tax Credits (255)	266-267	8,901,069	8,339,469
49	Deferred Gains from Disposition of Utility Plant (256)		0	0
50	Other Deferred Credits (253)	269	20,621,958	14,990,692
51	Other Regulatory Liabilities (254)	278	0	0
52	Unamortized Gain on Reaquired Debt (257)		0	0
53	Accumulated Deferred Income Taxes (281-283)	272-277	27,690,185	28,098,572
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		57,213,212	51,428,733
55			0	0
56			0	0
57			0	0
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		446,684,704	719,581,699

Statement B

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 1998

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	138,253,165	150,588,259
3	Operating Expenses			
4	Operation Expenses (401)	320-323	82,166,011	90,855,451
5	Maintenance Expenses (402)	320-323	6,298,852	5,881,135
6	Depreciation Expense (403)	336-337	13,861,917	13,490,813
7	Amort. & Depl. of Utility Plant (404-405)	336-337	777,678	294,468
8	Amort. of Utility Plant Acq. Adj. (406)	336-337		
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	6,245,725	6,870,252
14	Income Taxes - Federal (409.1)	262-263	2,433,575	11 [illegible]35,545
15	- Other (409.1)	262-263	132,897	136,230
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	3,135,299	-5,501,045
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,065,700	299,997
18	Investment Tax Credit Adj. - Net (411.4)	266	-561,600	-559,172
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		113,474,654	122,403,680
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		24,778,511	28,184,579

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.

B. Enter on pages 122-123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages.122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
78,414,964	76,726,821	59,838,201	73,861,438			2
						3
30,260,333	27,882,936	51,905,678	62,972,515			4
5,322,110	4,978,029	976,742	903,106			5
11,362,911	11,105,123	2,499,006	2,385,690			6
506,605	200,188	271,073	94,280			7
						8
						9
						10
						11
						12
5,355,701	5,383,189	890,024	1,487,063			13
3,313,145	8,645,665	-829,570	2,589,880			14
28,783	56,688	104,114	79,542			15
726,114	-3,340,618	2,409,185	-2,160,427			16
966,100	200,397	99,600	99,600			17
-513,600	-511,869	-48,000	-47,303			18
						19
						20
						21
						22
55,396,002	54,198,934	58,078,652	68,204,746			23
23,018,962	22,527,887	1,759,549	5,656,692			24

Statement B

Name of Respondent	This Report Is.	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 1998

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		24,778,511	28,184,579
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)			1,076,659
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			767,777
31	Revenues From Nonutility Operations (417)			9,396,703
32	(Less) Expenses of Nonutility Operations (417.1)			9,379,070
33	Nonoperating Rental Income (418)			
34	Equity in Earnings of Subsidiary Companies (418.1)	119	10,909,862	12,549,445
35	Interest and Dividend Income (419)		1,090,964	721,200
36	Allowance for Other Funds Used During Construction (419.1)		23,564	-27,650
37	Miscellaneous Nonoperating Income (421)		235,677	36,948
38	Gain on Disposition of Property (421.1)			800
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		12,260,067	13,607,258
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)			-70
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	430,431	558,508
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		430,431	558,438
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263		
47	Income Taxes-Federal (409.2)	262-263	5,535,771	4,161,393
48	Income Taxes-Other (409.2)	262-263		
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,841,214	-1,453,317
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		
51	Investment Tax Credit Adj.-Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		3,694,557	2,722,076
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		8,135,079	10,326,744
55	Interest Charges			
56	Interest on Long-Term Debt (427)		15,316,507	14,697,233
57	Amort. of Debt Disc. and Expense (428)		239,513	247,184
58	Amortization of Loss on Reaquired Debt (428.1)			
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340	-9,872,902	-97,617
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		47,841	-61,544
64	Net Interest Charges (Enter Total of lines 56 thru 63)		5,635,277	14,908,344
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		27,278,313	23,602,979
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		27,278,313	23,602,979

Statement C

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 1998

STATEMENT OF RETAINED EARNIGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		45,550,146
2	Changes		
3	Adjustments to Retained Earnings (Account 216)		
4			
5			
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		
10			
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		
16	Balance Transferred from Income (Account 433 less Account 418.1		16,368,451
17	Appropriations of Retained Earnings (Acct. 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		
23	Dividends Declared-Preferred Stock (Account 437)		
24	4 1/2% Series		-117,000
25	6 1/2% Series		-74,750
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-191,750
30	Dividends Declared-Common Stock (Account 438)		
31	$.99 Per Share		-18,901,818
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-18,901,818
37	Transfers from Acct 216.1, Unappropriated Undistributed Subsid Earngs		
38	Balance-End of Year		42,825,029

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
Northwestern Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec. 31, 1998

STATEMENT OF RETAINED EARNIGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
39			
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)		
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal		
47	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)		
48	TOTAL Retained Earnings (Account 215, 215.1, 216)		42,825,029
49	Balance-Beginning of Year (Debit or Credit)		27,365,095
50	Equity in Earnings for Year (Credit) (Account 418.1)		10,909,862
51	(Less) Dividends Received (Debit)		
52			
53	Balance-End of Year		38,274,957

Notes to Consolidated Financial Statements

1. Significant Accounting Policies

Nature of Operations:

NorthWestern Corporation (the Corporation) is a service and solutions company providing energy, communications and related services to customers throughout North America. A division of the Corporation is engaged in the regulated energy business of production, purchase, transmission, distribution and sale of electricity and the delivery of natural gas to Midwestern customers. Through CornerStone Propane Partners, L.P. (CornerStone), the Corporation is engaged in retail and wholesale propane distribution business located throughout North America. CornerStone is a publicly traded Delaware limited partnership, formed to acquire and operate propane businesses and assets. A wholly owned subsidiary of the Corporation serves as the general partner of CornerStone and manages and operates CornerStone's business. (For a detailed description of the Partnership Formation and related transactions, see Note 2.) At December 31, 1998, the Corporation owns a combined 30% effective interest in the Partnership. Through Blue Dot Services Inc. (Blue Dot, formerly ServiCenter USA), the Corporation has become a national provider of heating, ventilating, air conditioning, plumbing and related services (HVAC) by acquiring existing companies throughout the U.S. Through Expanets, Inc. (Expanets, formerly Communication Systems USA), the Corporation has become a national provider of integrated communications, data solutions and network services to business customers by acquiring companies throughout the U.S.

Basis of Consolidation:

The accompanying consolidated financial statements include the accounts of the Corporation and all wholly and majority-owned or controlled subsidiaries, including CornerStone, Blue Dot, and Expanets. All significant intercompany balances and transactions have been eliminated from the consolidated financial statements. The Corporation's regulated businesses are subject to various state and federal agency regulation. The public unitholders' interest in CornerStone's net assets subsequent to the Partnership Formation is reflected as a minority interest in the consolidated financial statements. Equity interest of the former owners of companies acquired by Blue Dot, and Expanets who continue to hold an interest in Blue Dot, and Expanets are reflected as minority interests in the consolidated financial statements.

Use of Estimates:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash Equivalents:

The Corporation generally considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents.

Accounts Receivable, net:

Accounts receivable is stated net of allowance for doubtful accounts of $6.1 million and $3.6 million at December 31, 1998 and 1997.

Investments and Fair Value of Financial Instruments:

The Corporation's investments consist primarily of short-maturity, fixed-income securities and corporate preferred and common stocks. In addition, the Corporation has investments in privately held entities and ventures, safe harbor leases and various money market and tax exempt investment programs. These investments are accounted for in accordance with Statement of Financial Accounting Standards No. 115 (SFAS 115), "Accounting for Certain Investments in Debt and Equity Securities." SFAS 115 requires that certain investments in debt and equity securities be reported at fair value.

The Corporation's securities are classified under the provisions of SFAS 115 as follows (in thousands):

	Fair Value	Cost	Unrealized Gain
December 31, 1998:			
Preferred Stocks	$41,547	$39,560	$1,987
Marketable Securities	30,045	27,376	2,669
December 31, 1997:			
Preferred Stocks	$84,349	$82,197	$2,652
Marketable Securities	29,470	23,094	6,376

The combined unrealized gain, net of tax, at December 31, 1998 and 1997, was $3.0 million and $5.9 million. Held to maturity securities are reported at cost, which approximated fair value and at December 31, 1998 and 1997, was $30.9 million and $27.3 million.

The Corporation uses the specific identification method for determining the cost basis of its investments in available for sale securities. Gross proceeds and realized gains and losses on sales of its available for sale securities were not material in 1998, 1997 and 1996.

Based on current market rates for debt of similar credit quality and remaining maturities or quoted market prices for certain issues, the face value of the Corporation's long-term debt approximates its market value.

CornerStone routinely uses commodity futures contracts to reduce the risk of future price fluctuations for natural gas

Notes to Consolidated Financial Statements (continued)

and liquefied petroleum gas (LPG) inventories and contracts. Gains and losses on futures contracts purchased as hedges are deferred and recognized in cost of sales as a component of the product cost for the related hedged transaction. Net realized gains and losses on these contracts are generally not material.

Revenue Recognition:

Electric and natural gas revenues are based on billings rendered to customers rather than on meters read or energy delivered. Customers are billed monthly on a cycle basis. Revenues from propane sales are recognized principally when fuel products are shipped or delivered to customers. HVAC and communication revenues are recognized as goods are delivered to customers or services are performed.

Property, Plant and Equipment:

Property, plant and equipment are stated at cost of acquisition less a depreciation reserve. Depreciation is computed using the straight-line method based on the estimated useful lives of the various classes of property. Depreciable property has estimated useful lives which range from 3 to 40 years.

Depreciation rates include a provision for the Corporation's share of the estimated costs to decommission three coal-fired generating plants at the end of the useful life of each plant. The annual provision for such costs is included in depreciation expense, while the accumulated provisions are included in other noncurrent assets.

When property for the propane, HVAC or communications interests are retired or otherwise disposed, the cost and related accumulated depreciation is removed from the accounts, and the resulting gain or loss is credited or charged to operations. No profit or loss is recognized in connection with ordinary retirements of depreciable electric and natural gas property. Maintenance and repairs are expensed as incurred, while replacements and betterments that extend estimated useful lives are capitalized. Property, plant and equipment at December 31 consisted of the following (in thousands):

	1998	1997
Land and improvements	$ 19,871	$ 15,308
Building and improvements	66,941	63,658
Storage, distribution, transmission and generation	611,052	567,514
Other equipment	128,002	73,912
	825,866	720,392
Less accumulated depreciation	(196,588)	(175,270)
	$629,278	$545,622

Computer Software Costs:

The Corporation includes in property, plant and equipment external and incremental internal costs associated with computer software we develop for use in our businesses. Capitalization begins when the costs of the preliminary stage of the project is completed. These costs are amortized on a straight-line basis over an estimated useful life once the installed software is ready for its intended use.

Goodwill and Other Intangibles:

The excess of the cost of businesses acquired over the fair market value of all tangible and intangible assets acquired, net of liabilities assumed, has been recorded as goodwill. Other intangibles consists principally of costs of covenants not to compete. Intangibles and goodwill are being amortized over the estimated periods benefited, which range from 3 to 40 years. Financing costs are amortized over the term of the applicable debt.

The Corporation's policy is to review property, goodwill and other intangible assets for possible impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such review indicates that the carrying amount is not recoverable, the Corporation's policy is to reduce the carrying amount of these assets to fair value.

(in thousands)	1998	1997
Goodwill	$611,847	$231,459
Noncompete agreements	17,585	4,266
Financing costs	21,936	7,949
	651,368	243,674
Less accumulated amortization	(20,339)	(6,630)
	$631,029	$237,044

Income Taxes:

Deferred income taxes relate primarily to the difference between book and tax methods of depreciating property, the difference in the recognition of revenues for book and tax purposes, and natural gas costs, which are deferred for book purposes but expensed currently for tax purposes.

For book purposes, investment tax credits were deferred and are being amortized as a reduction of income tax expense over the useful lives of the property which generated the credits.

Regulatory Assets and Liabilities:

The regulated operations of the Corporation are subject to the provisions of Statement of Financial Accounting Standards No. 71 (SFAS 71), "Accounting for the Effects of Certain Types of Regulations." Regulatory assets represent probable future revenue to the Corporation associated with certain costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.

Notes to Consolidated Financial Statements (continued)

If all or a separable portion of the Corporation's operations becomes no longer subject to the provisions of SFAS 71, an evaluation of future recovery from related regulatory assets and liabilities would be necessary. In addition, the Corporation would determine any impairment to the carrying costs of deregulated plant and inventory assets.

New Accounting Standards:

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." The Statement establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments imbedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS 133 is effective for fiscal years beginning after June 15, 1999. The Corporation is evaluating the impacts of adopting SFAS 133 on its financial statements. The impact of SFAS 133 will likely depend upon the extent of use of derivative instruments and their designation and effectiveness as hedges of market risk.

Reclassifications:

Certain 1997 and 1996 amounts have been reclassified to conform to the 1998 presentation. Such reclassifications had no impact on net income or shareholders' equity as previously reported. Shares outstanding and earnings per share amounts have been adjusted to reflect the May 1997 stock split.

Supplemental Cash Flow Information:

(in thousands)	1998	1997	1996
Cash paid during the year for:			
Income taxes	$17,629	$ 8,940	$ 6,271
Interest	35,162	30,090	18,645
Noncash transactions during the year for:			
Assumption of debt as part of acquisitions	28,572	1,551	149,516

2. Business Combinations and Acquisitions

Master Limited Partnership Offering and Acquisitions:

On December 17, 1996, a wholly owned subsidiary of NorthWestern Growth Corporation acquired CGI Holdings, Inc. (Coast). Immediately after the acquisition, the Corporation combined the propane distribution businesses of Coast, Empire Energy Corporation (Energy), Myers Propane Gas Corporation (Myers), and Synergy Group Incorporated (Synergy) into CornerStone. As part of an IPO on the same date, CornerStone sold a total of 9,821,000 Common Units at a price to the public of $21 a Unit. In January 1998, CornerStone sold an additional 1,960,000 Common Units at a price to the public of $22.125 per Unit.

The net proceeds of $191.8 million from the sale of 9,821,000 Common Units of CornerStone and the net proceeds from the issuance of $220 million face value of CornerStone Senior Notes were used to repay term and revolving debt of Coast, Energy and Synergy, including accrued interest and any prepayment premiums which were assumed by the Partnership. In addition, the preferred stock of Synergy was redeemed at a premium. As a result of these repayments, the Corporation recorded a one-time, after-tax gain of $.09 per share from the prepayment of the term debt and redemption of preferred stock investment in Synergy.

On December 11, 1998, the Partnership acquired the operations of Propane Continental, Inc. (PCI), a retail and wholesale propane distributor for approximately $121 million, including debt to be refunded. The acquisition was financed with Common Unit equity and long-term debt. The acquisition was accounted for under the purchase method of accounting. PCI operates 34 retail propane customer service centers in 11 states. Through Tri Power Fuels, PCI's wholesale business, PCI distributes propane and other natural gas liquids to independent dealers, resellers and end users predominately in the West, Midwest and Northeast sections of the country.

On December 31, 1998, the Partnership acquired the operations of ERI Services Canada, Ltd. and ERI Services, Inc. for approximately $4.5 million. Both of these entities are engaged in wholesale natural gas purchases and sales. The majority of their business is in Canada with a limited amount of business in the northeastern U.S.

At December 31, 1998, CornerStone's capital consisted of 10,444,096 Common Units, 6,597,619 Subordinated Units representing limited partner interests and a 2% aggregate general partner interest. At December 31, 1998, the Corporation's wholly and majority-owned subsidiaries owned all 6,597,619 Subordinated Units and an aggregate 2% general partner interest in the Partnership, or a combined 30% effective interest in the Partnership.

Blue Dot Services Inc.:

In 1997, NorthWestern formed Blue Dot, to acquire and operate HVAC companies in the U.S. At December 31, 1998, Blue Dot, had acquired 28 companies in 13 states with a total NorthWestern investment of $87.0 million. At December 31,

Notes to Consolidated Financial Statements (continued)

1998. NorthWestern owned a 94.8% voting interest in Blue Dot, through common and preferred stock ownership.

Expanets, Inc.:

In 1997, NorthWestern formed Expanets to acquire and operate communication companies in the U.S. At December 31, 1998, Expanets had acquired 18 companies in 25 states with a total NorthWestern investment of $108.3 million. At December 31, 1998, NorthWestern owned a 93.8% voting interest in Expanets through common and preferred stock ownership.

The acquisitions made by Blue Dot, and Expanets were effected utilizing cash or stock (of Blue Dot, or Expanets) and generally with a combination of both. In connection with certain acquisitions where the merger consideration included stock, both Blue Dot, and Expanets entered into exchange agreements with the sellers that typically do not exceed two years. Under such agreements, the seller can elect to exchange the stock of Blue Dot, or Expanets that they received in connection with the acquisition back to the Corporation for, at the Corporation's option, either stock of the Corporation or cash at a predetermined exchange rate.

All acquisitions of CornerStone, Blue Dot, and Expanets were accounted for under the purchase method of accounting with the excess of the purchase price over the fair value of assets acquired recorded as goodwill based upon the preliminary estimates of fair value and are subject to further changes. Had the acquisitions of CornerStone, Blue Dot, and Expanets occurred on January 1, 1997, combined unaudited pro forma results for the year ended December 31, 1997, as prescribed under Accounting Principles Board Opinion No. 16 (APB 16), "Business Combinations," would have been: revenues $1.8 billion, net income $37.7 million and diluted earnings per share $1.34. The combined unaudited pro forma results for the year ended December 31, 1998, would have been: revenues $2.0 billion, net income $41.1 million and diluted earnings per share $1.48. The pro forma disclosures required under APB 16 are not indicative of past or future operating results.

3. Short-Term Borrowings

The Corporation may issue short-term debt in the form of bank loans and commercial paper as interim financing for general corporate purposes. The bank loans may be obtained under short-term lines of credit. At December 31, 1998, the Corporation's aggregate lines of credit available were $75 million. The Corporation pays an annual fee generally equivalent to .1% to .25% of the unused lines. There were no line of credit borrowings or commercial paper outstanding at December 31, 1998 and 1997.

Expanets entered into a Bank Credit Facility in December 1998 with a commercial bank. The Bank Credit Facility consists of a $15 million Working Capital Facility. There were $11.6 million of borrowings outstanding under the Working Capital Facility at December 31, 1998. The Bank Credit Facility bears interest at a variable rate tied to the Eurodollar or prime rate plus a stated margin for each rate. The Bank Credit Facility matures in June 1999. The Facility is not secured, however, Expanets is subject to restrictive covenants which include a) restrictions on other indebtedness, b) limits on mergers, acquisitions and dispositions, and c) minimum investment in Expanets by the Corporation.

4. Long-Term Debt

Substantially all of the Corporation's electric and natural gas utility plant is subject to the lien of the indentures securing its general mortgage bonds and pollution control obligations. General mortgage bonds of the Corporation may be issued in amounts limited by property, earnings and other provisions of the mortgage indenture. In March 1997, the Corporation retired early the $7.5 million outstanding of the 8.9% series general mortgage bonds. In July 1997, the Corporation retired early the $15 million outstanding of the 8.824% series general mortgage bonds. As part of a financing transaction in November 1998, the Corporation issued $105 million of 6.95%, 30-year senior unsecured debt. The proceeds were used to repay short-term indebtedness and for general corporate purposes. The following tables summarize the Corporation's long-term obligations at December 31 (in thousands):

	Due	1998	1997
Long-Term Debt:			
Senior Unsecured Debt – 6.95%	2028	$105,000	$ —
General mortgage bonds –			
6.99%	2002	20,000	25,000
7.10%	2005	60,000	60,000
7%	2023	55,000	55,000
Pollution control obligations –			
5.85%, Mercer Co., ND	2023	7,550	7,550
5.90%, Salix, IA	2023	4,000	4,000
5.90%, Grant Co., SD	2023	9,800	9,800
Less current maturities		(5,000)	(5,000)
		$256,350	$156,350
Long-Term Debt of Subsidiaries – nonrecourse:			
Senior Secured Debt –			
7.53%	2010	$220,000	$220,000
7.33%	2010	85,000	—
Bank Credit Facility	1999	1,700	30,000
Other term debt		40,885	15,745
Less current maturities		(15,060)	(2,814)
		$332,525	$268,931

In conjunction with the Partnership Formation in December 1996, the Partnership issued $220 million in First Mortgage Notes (Mortgage Notes). These Mortgage Notes are

Notes to Consolidated Financial Statements (continued)

collateralized by substantially all of the assets of the Partnership and rank pari passu with the Bank Credit Facility. The Mortgage Notes bear interest at a fixed rate of 7.53% payable semi-annually and mature in the year 2010 with eight equal annual installments beginning in the year 2003. The Partnership may, at its option and under certain circumstances following the disposition of assets, be required to offer to prepay the Mortgage Notes in whole or in part. The Mortgage Notes agreement contains restrictive covenants applicable to the Partnership including a) restrictions on the incurrence of additional indebtedness, b) restrictions on the ratio of consolidated cash flow to consolidated interest expense of the Partnership, as defined, and c) restrictions on certain liens, loans and investments, payments, mergers, consolidations, sales of assets and other transactions. Generally, as long as no default exists or would result, the Partnership is permitted to make cash distributions not more frequently than quarterly in an amount not to exceed available cash, as defined, for the immediately preceding calendar quarter.

As part of a financing transaction in December 1998, the Partnership issued $85 million of Senior Secured Notes (Senior Notes). These Senior Notes are collateralized by substantially all of the assets of the Partnership and ranks pari passu with existing notes and borrowings under the Bank Credit Facility. The Senior Notes bear interest at a fixed rate of 7.33% payable semi-annually and mature in the year 2010 with eight annual installments beginning in the year 2003. The Senior Notes agreement contains the same restrictive covenants as those associated with the 1996 Mortgage Notes.

The Partnership also has a Bank Credit Facility with a group of commercial banks. The Bank Credit Facility consists of a combined $110 million Working Capital and Acquisition Facilities to finance propane business acquisitions. There were $1.7 million of combined borrowings outstanding under the Working Capital and Acquisition Facilities. There were $56.0 million of combined borrowings outstanding under the Working Capital and the Acquisition Facilities at December 31, 1997. The Bank Credit Facility bears interest at a variable rate tied to a certain Eurodollar index or prime rate plus a variable margin for either rate which depends upon the Partnership's ratio of consolidated debt to consolidated cash flow. The Bank Credit Facility matures in December 1999. The Bank Credit Facility is collateralized by substantially all the assets of the Partnership and ranks pari passu with the Mortgage Notes. The Bank Credit Facility contains restrictive covenants applicable to the Partnership including a) restrictions on the incurrence of additional indebtedness, b) restrictions on the ratio of consolidated cash flow to consolidated interest expense of the Partnership, as defined, and c) restrictions on certain liens, loans and investments, payments, mergers, consolidations, sales of assets and other transactions. They also require that the Partnership maintain a ratio of total funded indebtedness to consolidated cash flow, as defined. Generally, as long as no default exists or would result, the Partnership is permitted to make cash quarterly distributions in an amount not to exceed Available Cash, as defined.

The balance of other nonrecourse debt is generally comprised of the debt assumed and issued in conjunction with acquisitions of $40.9 million and $15.8 million at December 31, 1998 and 1997.

Annual scheduled consolidated retirements of long-term debt during the next five years are $20.1 million in 1999, $10.2 million in 2000, $8.9 million in 2001, $8.0 million in 2002 and $40.2 million in 2003.

5. Income Taxes

Income tax expense is comprised of the following (in thousands):

	1998	1997	1996
Federal income:			
Current tax expense	$12,945	$ 4,620	$ 9,174
Deferred tax expense	(1,069)	6,512	5,830
Investment tax credit	(562)	(539)	(561)
State income	1,882	538	972
	$13,196	$11,111	$15,415

The following table reconciles the Corporation's effective income tax rate to the federal statutory rate:

	1998	1997	1996
Federal statutory rate	35%	35%	35%
State income, net of federal benefit	2	1	2
Amortization of investment tax credit	(1)	(2)	(1)
Dividends received deduction	(7)	(2)	(1)
Other, net	1	1	2
	30%	33%	37%

The components of the net deferred income tax liability recognized in the Corporation's Consolidated Balance Sheets are related to the following temporary differences at December 31 (in thousands):

	1998	1997
Excess tax depreciation	$(80,550)	$(79,360)
Safe harbor leases	(4,192)	(4,514)
Property basis and life differences	(11,027)	(12,902)
Asset sales	(3,967)	(4,273)
Regulatory assets	(2,732)	(3,057)
Regulatory liabilities	4,125	4,512
Unbilled revenue	2,960	5,746
Unamortized investment tax credit	3,355	3,491
Unrealized gain on investments	(1,936)	(1,939)
Other, net	21,840	20,573
	$(72,924)	$(72,723)

Notes to Consolidated Financial Statements (continued)

6. Team Member Benefit Plans

The Corporation maintains a noncontributory defined benefit pension plan. The benefits to which a team member is entitled under the plan are derived using a formula based on the number of years of service and compensation levels, as defined. The Corporation determines the annual funding for its plan using the frozen initial liability cost method. The Corporation's annual contribution is funded in accordance with the requirements of ERISA. Assets of the plan consist primarily of debt and equity securities.

Following is a reconciliation of the changes in the plan's benefit obligations and fair value of assets over the two-year period ending December 31, 1998, and a statement of the funded status as of December 31 of both years (in thousands):

	1998	1997
Reconciliation of benefit obligation:		
Obligation at January 1	$54,656	$50,058
Service cost	1,012	981
Interest cost	3,689	3,499
Participant contributions	—	—
Amendments	—	1,779
Actuarial (gain) loss	1,009	1,712
Acquisition	—	—
Benefits paid	(3,049)	(3,373)
Benefit obligation at end of year	56,717	54,656
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	64,389	56,507
Actual return on plan assets	12,707	10,024
Acquisition	—	—
Employer contributions	—	1,231
Participant contributions	—	—
Benefits paid	(3,049)	(3,373)
Fair value of plan assets at end of year	73,447	64,389
Funded status:		
Funded status at December 31	16,730	9,734
Unrecognized transition amount	1,083	1,237
Unrecognized net actuarial loss	(10,755)	(10,665)
Unrecognized prior service cost	3,320	3,820
Prepaid (accrued) benefit cost	$ 4,378	$ 4,126

The following table provides the components of net periodic benefit cost for the plans for 1998, 1997 and 1996 (in thousands):

	1998	1997	1996
Service cost	$ 1,012	$ 981	$ 958
Interest cost	3,689	3,499	3,506
Expected return on plan assets	(5,307)	(4,681)	(4,377)
Amortization of transition (asset) obligation	155	155	155
Amortization of prior service cost	500	278	278
Amortization of net (gain) loss	(302)	(106)	(193)
Net periodic benefit cost	$ (253)	$ 126	$ 327

The prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10% of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

The assumptions used in calculating the projected benefit obligation for 1998, 1997 and 1996 were as follows:

	1998	1997	1996
Discount rate	6.75%	7.00%	7.25%
Expected rate of return on assets	8.50%	8.50%	8.50%
Long-term rate of increase in compensation levels	3.00%	3.00%	3.00%

The Corporation provides a team member savings plan, which permits a team member to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plan, a team member may elect to direct up to 12 percent of their gross compensation be contributed to the plan (subject to a maximum dollar amount as specified by applicable regulations). The Corporation contributes 50 cents for every one dollar contributed by the team member, up to a maximum Corporation contribution of 3% of the team member's gross compensation. The Corporation also provides an Employee Stock Ownership Plan (ESOP) for full-time team members. The ESOP is funded primarily with federal income tax savings, which arise from tax laws applicable to such team member benefit plans. Certain Corporation contributions and shares of stock acquired by the ESOP are allocated to participants' accounts in proportion to the compensation of team members during the particular year for which allocation is made. Costs incurred under the plan were $1.6 million, $1.5 million and $1.4 million in 1998, 1997 and 1996.

The Corporation also has various supplemental retirement plans for outside directors and selected management team members. The plans are nonqualified defined benefit plans that provide for certain amounts of salary continuation in the event of death before or after retirement or certain supplemental retirement benefits in lieu of any death benefits. In addition, the Corporation provides life insurance benefits to beneficiaries of eligible team members who represent a reasonable insurable risk. To minimize the overall cost of plans providing life insurance benefits, the Corporation has obtained life insurance coverage that is sufficient to fund benefit obligations. Costs incurred under the plans were $1.5 million, $1.2 million and $1.3 million in 1998, 1997 and 1996.

CornerStone has a Restricted Unit Plan (the "Restricted Unit Plan") which authorizes the issuance of Common Units with an aggregate value of $17.5 million to directors, executives, managers and selected supervisors of the Partnership. The value of the Restricted Common Unit is

Notes to Consolidated Financial Statements (continued)

established by the market price of the Common Unit at the date of grant. As of December 31, 1998, Restricted Common Units with a value of $13.8 million have been awarded.

CornerStone, Blue Dot, and Expanets provide various team member savings plans, which permit team members to defer receipt of compensation as provided in Section 401(k) of the Internal Revenue Code. Under the plans, the team member may elect to direct a percentage of their gross compensation be contributed to the plans. CornerStone, Blue Dot, and Expanets, at their discretion, may match a portion of the team member contribution.

7. Jointly Owned Plants

The Corporation has an ownership interest in three major electric generating plants, all of which are operated by other utility companies. The Corporation has an undivided interest in these facilities and is responsible for its proportionate share of the capital and operating costs while being entitled to its proportionate share of the power generated. The Corporation's interest in each plant is reflected in the Consolidated Balance Sheets on a prorate basis, and its share of operating expenses is reflected in the Consolidated Statements of Income. The participants each finance their own investment.

Information relating to the Corporation's ownership interest in these facilities at December 31, 1998, is as follows (in thousands):

	Big Stone	Neal #4	Coyote I
Plant in service	$46,313	$33,711	$40,640
Accumulated depreciation	$26,444	$13,059	$21,467

8. Operating Leases

The Corporation leases office, office equipment and warehouse facilities under various long-term operating leases. At December 31, 1998, future minimum lease payments under noncancelable lease agreements are as follows:

1999	$8,456
2000	7,204
2001	5,723
2002	4,087
2003	2,887
Thereafter	3,734

9. Stock Options and Warrants

In May 1998, the Corporation adopted the NorthWestern Stock Option and Incentive Plan (the "Plan"). Under the Plan, the Corporation has reserved 1,338,189 shares for issuance to officers, key team members and directors as either incentive-based options or nonqualified options. The Nominating and Compensation Committee of the Corporation's Board of Directors administers the Plan. Unless established differently by the Committee, the per share option exercise price shall be the fair market value of the Corporation's common stock at the grant date. The options are outstanding for 10 years following the date of grant. In addition, the Corporation issued 1,279,476 warrants to purchase shares of NorthWestern common stock in connection with a previous acquisition. A summary of the activity of stock options and warrants are as follows:

	Stock Options	
	Shares	Exercise Price
Outstanding at December 31, 1997	—	—
Issued	188,500	$23.00
Exercised	—	—
Outstanding at December 31, 1998	188,500	$23.00

	Stock Warrants	
	Shares	Exercise Price
Outstanding at December 31, 1997	—	—
Issued	1,279,476	$18.225
Exercised	174,318	$18.225
Outstanding at December 31, 1998	1,105,158	$18.225

The Corporation follows Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees," to account for stock option plans. No compensation cost is recognized because the option exercise price is equal to the market price of the underlying stock on the date of grant.

An alternative method of accounting for stock options is SFAS 123, "Accounting for Stock-Based Compensation." Under SFAS 123, team member stock options are valued at grant date using the Black-Scholes valuation model and compensation cost is recognized ratably over the vesting period. Had compensation cost for the Corporation's stock option plan been determined based on the Black-Scholes value at the grant dates for awards as prescribed by SFAS 123, the pro forma information for 1998 would have been as follows (in thousands except per share amounts):

Earnings on common stock:	
As reported	$27,030
Pro forma	$26,607
Diluted earnings per share:	
As reported	$1.44
Pro forma	$1.41

The weighted average Black-Scholes value of options granted under the stock option plan during 1998 was $3.91. The 1998 value was estimated using an expected life of eight years, 3.8% dividend yield, volatility of 16.9% and risk-free interest rate of 5.38%.

Notes to Consolidated Financial Statements (continued)

10. Earnings Per Share

In 1998, the Corporation adopted SFAS No. 128, "Earnings Per Share," which establishes two methods for calculating earnings per share, basic and diluted, and simplifies the previous standards for computing earnings per share. Basic earnings per share is computed on the basis of the weighted average number of common shares outstanding. Diluted earnings per share is computed on the basis of the weighted average number of common shares outstanding plus the effect of the outstanding stock options and warrants. The following table presents the shares used in computing the basic and diluted earnings per share for 1998, 1997 and 1996 (in thousands):

	1998	1997	1996
Average common shares outstanding for basic computation	18,000	17,843	17,840
Dilutive effect of:			
Stock options	5	—	—
Stock warrants	151	—	—
Average common shares outstanding for diluted computation	18,816	17,843	17,840

11. Partnership Distributions

The Partnership makes distributions to its partners with respect to each fiscal quarter of the Partnership in an aggregate amount equal to its Available Cash for such quarter. Available Cash generally means, with respect to any fiscal quarter of the Partnership, all cash on hand at the end of such quarter plus all additional cash on hand as of the date of determination resulting from borrowings subsequent to the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion for future cash requirements. These reserves are retained for the proper conduct of the Partnership's business, for the payment of debt principal and interest, and for distributions during the next four quarters.

Distributions by the Partnership, in an amount equal to 100% of its Available Cash, will generally be made 98% to the Common and Subordinated Unitholders and 2% to the General Partner. Distributions are subject to the payment of incentive distributions in the event Available Cash exceeds the Quarterly Distribution of $.594 on all Units. To the extent there is sufficient Available Cash, the holders of Common Units have the right to receive the Minimum Quarterly Distribution, plus any arrearages, prior to the distribution of Available Cash to holders of Subordinated Units. Common Units will not accrue arrearages for any quarter after the Subordination Period (as defined below), and Subordinated Units will not accrue any arrearages with respect to distributions for any quarter.

The Subordination Period will generally extend until the first day of any quarter beginning on or after December 31, 2001, in respect of which a) distributions of Available Cash from operating surplus equal or exceed the Minimum Quarterly Distribution on each of the outstanding Common and Subordinated Units for each of the three consecutive four-quarter periods immediately preceding such date, b) the adjusted operating surplus generated during each of the three consecutive four-quarter periods immediately preceding such date equals or exceeds the Minimum Quarterly Distribution on each of the Common and Subordinated Units and the related distribution on the General Partner interests in the Partnership during such periods, and c) there are no outstanding Common Unit arrearages.

In addition, 1,649,405 Subordinated Units will convert into Common Units for any quarter ending on or after December 31, 1999, and an additional 1,649,405 Subordinated Units will convert into Common Units for any quarter ending on or after December 31, 2000, if a) distributions of Available Cash from operating surplus on each of the outstanding Common and Subordinated Units equal or exceed the Minimum Quarterly Distribution for each of the three consecutive four-quarter periods immediately preceding such date, b) the adjusted operating surplus generated during the immediately preceding two consecutive four-quarter periods equals or exceeds the Minimum Quarterly Distribution on all of the Common and Subordinated Units outstanding during that period and c) there are no arrearages on the Common Units.

The Partnership will make distributions of its Available Cash approximately 45 days after the end of each quarter ending March, June, September and December to holders of record on the applicable record dates. For the quarter ended December 31, 1997, and year ended December 31, 1998, the Partnership and the Corporation elected to forgo the Subordinated Unit distributions continuing the support for the Common Unitholders.

12. Environmental Matters

The Corporation is subject to environmental regulations from numerous entities. The Clean Air Act Amendments of 1990 (the Act) stipulate limitations on sulfur dioxide and nitrogen oxide emissions from coal-fired power plants. The Corporation believes it can economically meet such sulfur dioxide emission requirements at its generating plants by the required compliance dates and that it is in compliance with all presently applicable environmental protection requirements and regulations. The Corporation is also subject to

Notes to Consolidated Financial Statements (continued)

other environmental regulations including matters related to former manufactured gas plant sites. In 1995, the Corporation remediated a site located at Huron, South Dakota, through thermal desorption of residues in the soil. Adjustments of the Corporation's natural gas rates to reflect the costs associated with the remediation were approved through the regulatory process. The Corporation is pursuing recovery from insurance carriers. No administrative or judicial proceedings involving the Corporation are now pending or known by the Corporation to be contemplated under present environmental protection requirements.

13. Capital Stock

In December 1996, the Corporation's Board of Directors declared, pursuant to a shareholders' rights plan, a dividend distribution of one Right on each outstanding share of the Corporation's common stock. Each Right becomes exercisable, upon the occurrence of certain events, at an exercise price of $50 per share, subject to adjustment. The Rights are currently not exercisable and will be exercisable only if a person or group of affiliated or associated persons (Acquiring Person) either acquires ownership of 15% or more of the Corporation's common stock or commences a tender or exchange offer that would result in ownership of 15% or more. In the event the Corporation is acquired in a merger or other business combination transaction or 50% or more of its consolidated assets or earnings power are sold, each Right entitles the holder to receive such number of shares of common stock of the Acquiring Person having a market value of two times the then current exercise price of the Right. The Rights, which expire in December 2006, are redeemable in whole, but not in part, at a price of $.005 per Right, at the Corporation's option at any time until any Acquiring Person has acquired 15% or more of the Corporation's common stock.

The Corporation is authorized to issue 1,000,000 shares of $100 par cumulative preferred stock. As of December 31, 1998 and 1997, there were 37,500 shares outstanding of which 26,000 were 6 1/2% Series and 11,500 were 4 1/2% Series. The provisions of the 6 1/2% Series stock contain a five-year put option exercisable by the holders of the securities and a 10-year redemption option exercisable by the Corporation. In any event, redemption will occur at par value. The 4 1/2% Series may be redeemed in whole or in part at the option of the Board of Directors at any time upon at least 30 days notice at $110.00 per share plus accrued dividends.

In the event of involuntary dissolution, all Corporation preferred stock outstanding would have a preferential interest of $100 per share, plus accumulated dividends, before any distribution to common shareholders.

There were 2,500 shares of subsidiary preferred stock outstanding at December 31, 1996. The subsidiary preferred stock was redeemed in January 1997.

The Corporation is also authorized to issue a maximum of 1,000,000 shares of preference stock at a par value of $50 per share. No preference shares have ever been issued.

As of December 31, 1998 and 1997, the Corporation had 3,500,000 and 1,300,000 shares of preferred securities outstanding. The 1,300,000 outstanding at December 31, 1997, were issued in 1995 at 8 1/8% with a $25 par value. The additional 2,200,000 shares were issued as part of a financing transaction in November 1998 when the Corporation sold $55,000,000 of its 7.2% preferred capital securities at $25 par value. The proceeds were used for general corporate purposes.

14. Segment and Related Information

In 1998, the Corporation adopted Statement of Financial Accounting Standards No. 131 (SFAS 131), "Disclosures About Segments of an Enterprise and Related Information," which requires the reporting of certain financial information by business segment. For the purpose of providing segment information, the Corporation's six principal business segments are its electric, natural gas, retail propane, wholesale propane, HVAC and communications operations. All other includes the results of the manufacturing operations, activities and assets of the parent, any reconciling or eliminating amounts and amortization of purchase accounting adjustments of $3.8 million in 1998 related to the acquisitions of HVAC and communication companies.

The accounting policies of the operating segments are the same as those described in the summary of significant accounting policies except that the parent allocates some of its operating expenses and interest expense to the operating segments according to a methodology designed by management for internal reporting purposes and involves estimates and assumptions. Financial data for the business segments are as follows (in thousands):

Notes to Consolidated Financial Statements (continued)

	Total Electric and Natural Gas	Total Propane	HVAC	Communications	All Other	Total
1998						
Operating revenues	$145,045	$707,735	$126,510	$127,898	$ 19,999	$1,187,187
Cost of sales	62,595	618,734	77,045	71,214	10,179	839,787
Gross margins	83,050	148,981	49,465	56,684	9,220	347,400
Selling, general and administrative	37,445	105,520	36,690	42,964	8,214	230,833
Depreciation and amortization	14,759	20,154	1,659	1,701	4,353	42,626
Operating income	30,846	23,307	11,116	12,019	(3,347)	73,941
Interest expense	(12,059)	(20,321)	(25)	(501)	(2,766)	(35,732)
Investment income and other	1,261	—	208	(17)	4,693	6,145
Income before taxes and minority interests	20,048	2,986	11,299	11,441	(1,420)	44,354
Provision for taxes	(7,379)	(999)	(4,301)	(3,523)	3,006	(13,196)
Income before minority interests	$ 12,669	$ 1,987	$ 6,998	$ 7,918	$ 1,586	$ 31,158
Total assets	$321,847	$759,232	$ 37,035	$ 77,418	$520,684	$1,736,216
Maintenance capital expenditures	$ 14,366	$ 2,898	$ 2,641	$ 2,161	$ 559	$ 22,625
1997						
Operating revenues	$154,288	$743,038	—	—	$ 20,744	$ 918,070
Cost of sales	69,595	612,305	—	—	13,145	695,045
Gross margins	84,693	130,733	—	—	7,599	223,025
Selling, general and administrative	36,384	90,344	—	—	6,065	132,793
Depreciation and amortization	13,901	16,784	—	—	550	31,235
Operating income	34,408	23,605	—	—	984	58,997
Interest expense	(12,186)	(18,980)	—	—	(310)	(31,476)
Investment income and other	689	—	—	—	10,875	11,564
Income before taxes and minority interests	22,911	4,625	—	—	11,549	39,085
Provision for taxes	(8,334)	(1,283)	—	—	(1,494)	(11,111)
Income before minority interests	$ 14,577	$ 3,342	—	—	$ 10,055	$ 27,974
Total assets	$306,930	$622,077	—	—	$177,116	$1,106,123
Maintenance capital expenditures	$ 18,210	$ 4,056	—	—	$ 134	$ 22,400
1996						
Operating revenues	$145,686	$175,102	—	—	$ 23,221	$ 344,009
Cost of sales	64,518	101,360	—	—	14,548	180,426
Gross margins	81,168	73,742	—	—	8,673	163,583
Selling, general and administrative	37,897	49,065	—	—	6,789	93,751
Depreciation and amortization	13,112	5,730	—	—	572	19,414
Operating income	30,159	18,947	—	—	1,312	50,418
Interest expense	(13,611)	(13,085)	—	—	8,028	(18,668)
Investment income and other	850	—	—	—	8,869	9,719
Income before taxes and minority interests	17,398	5,862	—	—	18,209	41,469
Provision for taxes	(5,741)	(2,879)	—	—	(6,795)	(15,415)
Income before minority interests	$ 11,657	$ 2,983	—	—	$ 11,414	$ 26,054
Total assets	$289,475	$611,707	—	—	$212,534	$1,113,716
Maintenance capital expenditures	$ 27,770	$ 7,349	—	—	$ 51	$ 35,170

Notes to Consolidated Financial Statements (continued)

	1998		1997		1996	
	Electric	Natural Gas	Electric	Natural Gas	Electric	Natural Gas
Operating revenues	$78,401	$67,244	$76,727	$77,561	$73,417	$72,269
Cost of sales	15,390	47,205	14,560	55,035	13,347	51,171
Gross margins	63,011	20,039	62,167	22,526	60,070	21,098
Selling, general and administrative	25,534	11,911	23,685	12,699	24,801	13,096
Depreciation and amortization	11,870	2,889	11,305	2,596	10,794	2,318
Operating income	$25,607	$ 5,239	$27,177	$ 7,231	$24,475	$ 5,684

	1998		1997		1996	
	Retail Propane	Wholesale Propane	Retail Propane	Wholesale Propane	Retail Propane	Wholesale Propane
Operating revenues	$297,779	$469,956	$243,589	$499,449	$153,571	$ 21,531
Cost of sales	165,526	453,228	127,529	484,776	80,264	21,096
Gross margins	$132,253	$ 16,728	$116,060	$ 14,673	$ 73,307	$ 435

15. Quarterly Financial Data (Unaudited)

(In Thousands Except Per Share Amounts)	First	Second	Third	Fourth
1998				
Operating revenues*	$298,964	$233,145	$276,896	$378,162
Operating income*	$ 29,836	$ 6,938	$ 11,545	$ 25,622
Net income	$ 11,004	$ 3,355	$ 4,582	$ 11,450
Average common shares outstanding	17,843	17,843	17,860	21,068
Basic earnings per average common share**	$ .58	$ .15	$ .21	$ .49
Diluted earnings per average common share**	$ .58	$ .15	$ .20	$ .48
1997				
Operating revenues	$284,406	$165,451	$185,084	$283,120
Operating income	$ 27,932	$ 4,497	$ 4,033	$ 22,535
Net income	$ 10,523	$ 3,158	$ 3,722	$ 8,861
Average common shares outstanding	17,842	17,843	17,843	17,843
Basic earnings per average common share	$ .55	$ .14	$ .17	$ .45
Diluted earnings per average common share	$ .55	$ .14	$ .17	$ .45

* Operating revenues and operating income for the first, second and third quarters have been restated to reflect the consolidation of Blue Dot, and Expanets effective January 1, 1998. There was no impact upon net income and earnings per share from those restated periods.

** The 1998 quarterly earnings per average common share do not total to the 1998 annual earnings per average common share due to the effect of common stock issuances during the year.

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NWPS CO.
COST OF PLANT - GAS - SOUTH DAKOTA
SUMMARY OF ADDITIONS AND REDUCTIONS DURING TEST PERIOD
DECEMBER 31, 1998 TEST YEAR
STATEMENT D

NO.	ACCOUNT DESCRIPTION	BEGINNING BALANCE 1-1-98	ADDITIONS	REDUCTIONS	ENDING BALANCE 12-31-98
101	GAS PLANT IN SERVICE	39,037,178.44	3,042,632.03	(369,319.18)	41,710,491.29
102	GAS PLANT PURCHASED OR SOLD	0.00			0.00
103	EXPERIMENTAL GAS PLANT UNCLASSIFIED	0.00			0.00
104	GAS PLANT LEASED TO OTHERS	0.00			0.00
105	GAS PLANT HELD FOR FUTURE USE	0.00			0.00
106	COMPLETED CONSTRUCTION NOT CLASSIFIED - GAS	745,185.72	0.00	(745,185.72)	0.00
107	CONSTRUCTION WORK IN PROGRESS - GAS	1,838,732.51	4,585,180.13	(2,293,766.06)	4,130,146.58
118	OTHER UTILITY PLANT	39,951,643.42	4,037,263.39	(3,501,480.92)	40,487,425.89

NWPS CO.
DETAIL PLANT ACCOUNTS - GAS - SOUTH DAKOTA
SUMMARY OF ADDITIONS AND REDUCTIONS DURING TEST PERIOD
DECEMBER 31, 1998 TEST YEAR
SCHEDULE D-1

NO.	ACCOUNT DESCRIPTION	BEGINNING BALANCE 1-1-98	ADDITIONS	REDUCTIONS	ENDING BALANCE 12-31-98
	PRODUCTION				
3040	LAND AND LAND RIGHTS	71,235.92	0.00	(31,179.35)	40,056.57
3050	STRUCTURES AND IMPROVEMENTS	263,049.53	0.00	0.00	263,049.53
3110	LIQUEFIED PETROLEUM GAS EQUIPMENT	1,495,716.06	0.00	0.00	1,495,716.06
3200	OTHER EQUIPMENT	11,566.54	0.00	0.00	11,566.54
	TOTAL PRODUCTION PLANT	1,841,568.05	0.00	(31,179.35)	1,810,388.70
	DISTRIBUTION				
3740	LAND AND LAND RIGHTS	190,890.66	16,563.92	0.00	207,454.58
3750	STRUCTURES AND IMPROVEMENTS	62,095.10	0.00	0.00	62,095.10
3760	MAINS	18,634,902.36	1,183,091.25	(35,852.68)	19,782,140.93
3780	MEASURING & REGULATING STATION EQUIP-GENERAL	438,356.73	82,221.93	59,691.04	580,269.70
3790	MEASURING & REGULATING STATION EQUIP-CITY	605,490.08	236,751.23	0.00	842,241.31
3800	SERVICES	8,142,318.45	588,055.01	(37,257.64)	8,693,115.82
3810	METERS	3,656,607.02	445,929.95	(38,307.91)	4,064,229.06
3820	METER INSTALLATION	1,280,458.44	293,144.80	(35,929.31)	1,537,673.93
3830	REGULATORS	788,765.67	31,153.13	(8,994.00)	810,924.80
3840	REGULATOR INSTALLATION	509,634.94	25,812.18	(11,045.69)	524,401.43
TOTAL	TOTAL DISTRIBUTION PLANT	34,309,519.45	2,902,723.40	(107,696.19)	37,104,546.66
	GENERAL				
3030	MISCELLANEOUS INTANGIBLE PLANT	2,930.90	4,396.35	0.00	7,327.25
3890	LAND AND LAND RIGHTS	42,184.10	450.00	0.00	42,634.10
3900	STRUCTURES AND IMPROVEMENTS	344,712.71	28,866.55	(1,020.00)	372,559.26
3910	OFFICE FURNITURE AND EQUIPMENT	39,603.41	1,345.77	0.00	40,949.18
3920	TRANSPORTATION EQUIPMENT	1,029,730.22	79,342.60	(189,550.11)	919,522.71
3930	STORES EQUIPMENT	7,608.81	0.00	0.00	7,608.81
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	436,565.12	19,570.80	0.00	456,135.92
3950	LABORATORY EQUIPMENT	225,951.79	2,882.67	0.00	228,834.46
3960	POWER OPERATED EQUIPMENT	673,145.79	1,009.98	0.00	674,155.77
3970	COMMUNICATION EQUIPMENT	82,444.32	2,043.91	(39,873.53)	44,614.70
3980	MISCELLANEOUS EQUIPMENT	1,213.77	0.00	0.00	1,213.77
	TOTAL GENERAL PLANT	2,886,090.94	139,908.63	(230,443.64)	2,795,555.93
	TOTAL 101	39,037,178.44	3,042,632.03	(369,319.18)	41,710,491.29
106	COMPLETED CONSTRUCTION NOT CLASSIFIED	745,185.72	0.00	(745,185.72)	0.00
	TOTAL GAS PLANT-SOUTH DAKOTA	39,782,364.16	3,042,632.03	(1,114,504.90)	41,710,491.29

NWPS
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
1998 CALENDAR YEAR
DECEMBER 31, 1998 TEST YEAR
SCHEDULE D-2

NO.	WORK ORDER DESCRIPTION	AMOUNT ADDITION	RETIREMENT	OTHER TRANSACTION	BALANCE	MAJOR ADDITIONS AND RETIREMENTS (CONSTRUCTION PERIOD) BEGINNING	ENDING	IN (OUT) SERVICE DATE
	BALANCE JANUARY 1, 1998				39,782,364.18			
	MAJOR ADDITIONS							
6563	AB-Random main and service installations	169,746.14				3-97	12-97	12-97
6571	AB-Replace bare main on 6th Ave from Main to Penn & 9th to 8th	114,422.83				2-97	12-97	12-97
6575	BG-Random main and service installations	265,388.05				1-97	12-97	6-97
6597	MI-Random main and service installations	204,944.55				1-97	12-97	1-97
6653	Purchase meters for South Dakota	205,104.07				2-97	12-97	Various
7087	Purchase meters for South Dakota	407,605.19				1-98	12-98	Various
	MAJOR RETIREMENTS							
	MINOR ADDITIONS							
	SPECIFIC WORK ORDERS (33)	744,159.32				Various	Various	Various
	PERMANENT WORK ORDERS	182,415.91				Various	Various	Various
	MINOR RETIREMENTS							
	SPECIFIC WORK ORDERS (11)		(81,229.18)			Various	Various	Various
	PERMANENT WORK ORDERS		(288,090.00)			Various	Various	Various
	CORRECTIONS OR TRANSFERS			3,680.25				
106	COMPLETED CONSTRUCTION NOT CLASSIFIED							
	DECEMBER 31, 1998 TEST YEAR TOTALS	2,293,786.06	(369,319.18)	3,680.25				
	BALANCE DECEMBER 31,1998				41,710,491.29			

NWPS CO.
MONTHLY BOOK BALANCES OF PLANT ACCOUNTS - GAS - SOUTH DAKOTA
DURING TEST PERIOD AND THIRTEEN MONTH AVERAGE BALANCES
DECEMBER 31, 1998 TEST YEAR
SCHEDULE D-3
PAGE 1 OF 2

ACCOUNT NO.	DESCRIPTION	1997 DECEMBER	JANUARY	FEBRUARY	1998 MARCH	APRIL	MAY	JUNE
	PRODUCTION							
3040	LAND AND LAND RIGHTS	71,235.92	71,235.92	71,235.92	71,235.92	40,056.57	40,056.57	40,056.57
3050	STRUCTURES AND IMPROVEMENTS	263,049.53	263,049.53	263,049.53	263,049.53	263,049.53	263,049.53	263,049.53
3110	LIQUEFIED PETROLEUM GAS EQUIPMENT	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06
3200	OTHER EQUIPMENT	11,566.54	11,566.54	11,566.54	11,566.54	11,566.54	11,566.54	11,566.54
	TOTAL PRODUCTION PLANT	1,841,568.05	1,841,568.05	1,841,568.05	1,841,568.05	1,810,388.70	1,810,388.70	1,810,388.70
	DISTRIBUTION							
3740	LAND AND LAND RIGHTS	190,890.66	190,440.66	190,440.66	190,440.66	196,576.41	207,454.58	207,454.58
3750	STRUCTURES AND IMPROVEMENTS	62,095.10	62,095.10	62,095.10	62,095.10	62,095.10	62,095.10	62,095.10
3760	MAINS	18,634,902.36	18,749,257.73	18,750,829.32	18,759,040.10	19,173,556.84	19,819,375.06	19,820,030.10
3780	MEASURING & REGULATING STATION EQUIP-GENERAL	438,356.73	438,356.73	438,356.73	438,356.73	438,356.73	504,122.05	504,756.99
3790	MEASURING & REGULATING STATION EQUIP-CITY	605,490.08	604,792.00	604,792.00	605,839.00	725,524.55	842,241.31	842,241.31
3800	SERVICES	8,142,318.45	8,143,901.51	8,144,446.58	8,144,115.82	8,519,557.95	8,729,000.41	8,729,657.89
3810	METERS	3,656,607.02	3,824,908.61	3,824,908.61	3,824,908.61	3,825,215.81	3,923,848.98	3,923,848.98
3820	METER INSTALLATION	1,280,458.44	1,300,306.66	1,300,306.66	1,300,306.66	1,392,069.53	1,499,586.39	1,499,586.39
3830	REGULATORS	788,765.67	799,745.03	799,745.03	799,745.03	803,325.13	812,340.87	812,340.87
3840	REGULATOR INSTALLATION	509,634.94	513,134.12	513,134.12	513,134.12	526,192.47	530,395.10	530,395.10
TOTAL	TOTAL DISTRIBUTION PLANT	34,309,519.45	34,626,938.15	34,629,054.81	34,637,981.83	35,662,470.52	36,930,459.85	36,932,407.31
	GENERAL							
3030	MISCELLANEOUS INTANGIBLE PLANT	2,930.90	2,930.90	2,930.90	2,930.90	2,930.90	2,930.90	2,930.90
3890	LAND AND LAND RIGHTS	42,184.10	42,634.10	42,634.10	42,634.10	42,634.10	42,634.10	42,634.10
3900	STRUCTURES AND IMPROVEMENTS	344,712.71	344,712.71	344,712.71	346,754.26	346,754.26	372,559.26	372,559.26
3910	OFFICE FURNITURE AND EQUIPMENT	39,603.41	39,603.41	39,603.41	40,154.66	40,154.66	40,154.66	40,154.66
3920	TRANSPORTATION EQUIPMENT	1,029,730.22	957,736.19	915,234.59	915,234.59	900,150.69	973,163.04	973,163.04
3930	STORES EQUIPMENT	7,608.81	7,608.81	7,608.81	7,608.81	7,608.81	7,608.81	7,608.81
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	436,565.12	443,626.03	444,398.77	444,398.77	444,398.77	444,398.77	444,398.77
3950	LABORATORY EQUIPMENT	225,951.79	225,951.79	225,951.79	225,951.79	228,834.46	228,834.46	228,834.46
3960	POWER OPERATED EQUIPMENT	673,145.79	673,145.79	673,145.79	674,155.77	674,155.77	674,155.77	674,155.77
3970	COMMUNICATION EQUIPMENT	82,444.32	82,444.32	82,444.32	82,444.32	82,444.32	84,488.23	84,488.23
3980	MISCELLANEOUS EQUIPMENT	1,213.77	1,213.77	1,213.77	1,213.77	1,213.77	1,213.77	1,213.77
	TOTAL GENERAL PLANT	2,886,090.94	2,821,607.82	2,779,878.96	2,783,481.74	2,771,280.51	2,872,141.77	2,872,141.77
	TOTAL 101	39,037,178.44	39,290,114.02	39,250,501.82	39,263,031.62	40,244,139.73	41,612,990.32	41,614,937.78
106	COMPLETED CONSTRUCTION NOT CLASSIFIED	745,185.72	745,185.72	745,185.72	745,185.72	745,185.72	0.00	0.00
	TOTAL GAS PLANT-	39,782,364.16	40,035,299.74	39,995,687.54	40,008,217.34	40,989,325.45	41,612,990.32	41,614,937.78

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NWPS CO.
MONTHLY BOOK BALANCES OF PLANT ACCOUNTS - GAS - SOUTH DAKOTA
DURING TEST PERIOD AND THIRTEEN MONTH AVERAGE BALANCES
DECEMBER 31, 1998 TEST YEAR
SCHEDULE D-3
PAGE 2 OF 2

ACCOUNT NO.	DESCRIPTION	1998 JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	THIRTEEN MONTH TOTAL	THIRTEEN MONTH AVERAGE
	PRODUCTION								
3040	LAND AND LAND RIGHTS	40,056.57	40,056.57	40,056.57	40,056.57	40,056.57	40,056.57	645,452.81	49,650.22
3050	STRUCTURES AND IMPROVEMENTS	263,049.53	263,049.53	263,049.53	263,049.53	263,049.53	263,049.53	3,419,643.89	263,049.53
3110	LIQUEFIED PETROLEUM GAS EQUIPMENT	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	1,495,716.06	19,444,308.78	1,495,716.06
3200	OTHER EQUIPMENT	11,566.54	11,566.54	11,566.54	11,566.54	11,566.54	11,566.54	150,365.02	11,566.54
	TOTAL PRODUCTION PLANT	1,810,388.70	1,810,388.70	1,810,388.70	1,810,388.70	1,810,388.70	1,810,388.70	23,659,770.50	1,819,982.35
	DISTRIBUTION								
3740	LAND AND LAND RIGHTS	207,454.58	207,454.58	207,454.58	207,454.58	207,454.58	207,454.58	2,618,425.69	201,417.36
3750	STRUCTURES AND IMPROVEMENTS	62,095.10	62,095.10	62,095.10	62,095.10	62,095.10	62,095.10	807,236.30	62,095.10
3760	MAINS	19,803,587.24	19,792,943.66	19,796,702.99	19,775,163.19	19,775,649.94	19,782,140.93	252,433,179.66	19,417,936.90
3780	MEASURING & REGULATING STATION EQUIP-GENERAL	511,337.58	512,266.06	510,265.34	576,140.96	580,401.95	580,269.70	6,471,344.28	497,795.71
3790	MEASURING & REGULATING STATION EQUIP-CITY	842,241.31	842,241.31	842,241.31	842,241.31	842,241.31	842,241.31	9,884,368.11	760,336.01
3800	SERVICES	8,737,140.16	8,725,065.19	8,723,445.19	8,700,103.87	8,696,943.41	8,693,115.82	110,826,812.25	8,525,293.25
3810	METERS	3,923,648.98	4,016,883.61	4,014,846.37	4,017,609.93	4,015,850.83	4,064,229.06	50,857,515.60	3,912,116.58
3820	METER INSTALLATION	1,499,586.39	1,532,473.34	1,532,473.34	1,499,963.50	1,507,618.93	1,537,673.93	18,682,410.16	1,437,108.47
3830	REGULATORS	812,340.87	819,654.11	819,654.11	810,924.80	810,924.80	810,924.80	10,500,431.12	807,725.47
3840	REGULATOR INSTALLATION	530,395.10	535,363.10	535,363.10	524,401.43	524,401.43	524,401.43	6,810,345.56	523,872.74
TOTAL	TOTAL DISTRIBUTION PLANT	36,930,027.31	37,046,440.46	37,044,541.43	37,016,098.67	37,023,582.28	37,104,546.66	469,894,068.73	36,145,697.59
	GENERAL								
3030	MISCELLANEOUS INTANGIBLE PLANT	7,327.25	7,327.25	7,327.25	7,327.25	7,327.25	7,327.25	64,479.80	4,959.98
3890	LAND AND LAND RIGHTS	42,634.10	42,634.10	42,634.10	42,634.10	42,634.10	42,634.10	553,793.30	42,599.48
3900	STRUCTURES AND IMPROVEMENTS	372,559.26	372,559.26	372,559.26	372,559.26	372,559.26	372,559.26	4,708,120.73	362,163.13
3910	OFFICE FURNITURE AND EQUIPMENT	40,154.66	40,949.18	40,949.18	40,949.18	40,949.18	40,949.18	524,329.43	40,333.03
3920	TRANSPORTATION EQUIPMENT	893,631.28	874,912.16	910,341.91	920,552.96	923,202.96	919,522.71	12,106,576.34	931,275.10
3930	STORES EQUIPMENT	7,608.81	7,608.81	7,608.81	7,608.81	7,608.81	7,608.81	98,914.53	7,608.81
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	444,398.77	456,135.92	456,135.92	456,135.92	456,135.92	456,135.92	5,827,263.37	448,251.03
3950	LABORATORY EQUIPMENT	228,834.46	228,834.46	228,834.46	228,834.46	228,834.46	228,834.46	2,963,317.30	227,947.48
3960	POWER OPERATED EQUIPMENT	674,155.77	674,155.77	674,155.77	674,155.77	674,155.77	674,155.77	8,760,995.07	673,922.70
3970	COMMUNICATION EQUIPMENT	84,488.23	84,488.23	84,488.23	84,488.23	84,488.23	44,614.70	1,048,253.91	80,634.92
3980	MISCELLANEOUS EQUIPMENT	1,213.77	1,213.77	1,213.77	1,213.77	1,213.77	1,213.77	15,779.01	1,213.77
	TOTAL GENERAL PLANT	2,797,006.36	2,790,818.91	2,826,248.66	2,836,459.71	2,839,109.71	2,795,555.93	36,671,822.79	2,820,909.45
									0.00
	TOTAL 101	41,537,422.37	41,647,648.07	41,681,178.79	41,662,947.08	41,673,080.69	41,710,491.29	530,225,662.02	40,786,589.39
106	COMPLETED CONSTRUCTION NOT CLASSIFIED	0.00	0.00	0.00	0.00	0.00	0.00	3,725,928.60	286,609.89
	TOTAL GAS PLANT-	41,537,422.37	41,647,648.07	41,681,178.79	41,662,947.08	41,673,080.69	41,710,491.29	533,951,590.62	41,073,199.28

NWPS
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
1997 CALENDAR YEAR
DECEMBER 31, 1998 TEST YEAR
SCHEDULE D-4
PAGE 1 OF 5

NO.	WORK ORDER DESCRIPTION	AMOUNT ADDITION	RETIREMENT	OTHER TRANSACTION	BALANCE	MAJOR ADDITIONS AND RETIREMENTS CONSTRUCTION PERIOD BEGINNING	ENDING	IN (OUT) SERVICE DATE
	BALANCE JANUARY 1, 1997				37,308,522.62			
	MAJOR ADDITIONS							
6134	AB-Random main and service installations	183,052.78				4-96	12-96	4-96
6144	BG-Random main and service installations	227,670.08				2-96	12-96	2-96
6158	HU-Random main and service installations	134,746.77				1-96	12-96	1-96
6168	MI-Random main and service installations	188,038.91				2-96	12-96	4-96
6222	Purchase meters and regulators for South Dakota & Nebrask	460,456.73				1-96	12-96	Various
6303	MI-Extend main to Universal Packaging	183,676.05				6-96	11-96	11-96
6653	Purchase meters for Nebraska and South Dakota	367,799.60				2-97	12-97	Various
	MAJOR RETIREMENTS							
6797	AB-Ret Propane Storage Tanks		(497,471.49)			12-97	12-97	12-97
	MINOR ADDITIONS							
	SPECIFIC WORK ORDERS (26)	588,686.58				Various	Various	Various
	PERMANENT WORK ORDERS	113,331.59				Various	Various	Various
	MINOR RETIREMENTS							
	SPECIFIC WORK ORDERS (14)		(64,566.83)			Various	Various	Various
	PERMANENT WORK ORDERS		(60,510.49)			Various	Various	Various
	CORRECTIONS OR TRANSFERS			(96,254.46)				
106	COMPLETED CONSTRUCTION NOT CLASSIFIED							
6585	BG-Ext Gas Serv-Hayti	153,849.51				5-97	9-97	7-97
6657	GO-Ext Serv to Hutterite	591,336.21				7-97	12-97	9-97
	DECEMBER 31, 1997 TEST YEAR TOTALS	3,192,644.81	(622,548.81)	(96,254.46)				
	BALANCE DECEMBER 31,1997				39,782,364.16			

NWPS
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
1996 CALENDAR YEAR
DECEMBER 31, 1996 TEST YEAR
SCHEDULE D-4
PAGE 2 OF 5

NO.	WORK ORDER DESCRIPTION	AMOUNT ADDITION	RETIREMENT	OTHER TRANSACTION	BALANCE	MAJOR ADDITIONS AND RETIREMENTS CONSTRUCTION PERIOD BEGINNING	ENDING	IN (OUT) SERVICE DATE
	BALANCE JANUARY 1, 1996				36,061,587.43			
	MAJOR ADDITIONS							
5525	Extend Mains & Services - AB	100,665.77				4-95	12-95	6-95
5553	Install Random Services - BG	281,981.35				1-95	12-95	3-95
	MAJOR RETIREMENTS							
	MINOR ADDITIONS							
	SPECIFIC WORK ORDERS (55)	991,653.89				Various	Various	Various
	PERMANENT WORK ORDERS	79,769.48				Various	Various	Various
	MINOR RETIREMENTS							
	SPECIFIC WORK ORDERS (19)		(108,404.64)			Various	Various	Various
	PERMANENT WORK ORDERS		(74,506.85)			Various	Various	Various
	CORRECTIONS OR TRANSFERS			(24,223.81)				
106	COMPLETED CONSTRUCTION NOT CLASSIFIED							
	DECEMBER 31, 1996 TEST YEAR TOTALS	1,454,070.49	(182,911.49)	(24,223.81)				
	BALANCE DECEMBER 31,1996				37,308,522.62			

NWPS
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
1995 CALENDAR YEAR
DECEMBER 31, 1995 TEST YEAR
SCHEDULE D-4
PAGE 3 OF 5

NO	WORK ORDER DESCRIPTION	AMOUNT ADDITION	RETIREMENT	OTHER TRANSACTION	BALANCE	MAJOR ADDITIONS AND RETIREMENTS CONSTRUCTION PERIOD BEGINNING	CONSTRUCTION PERIOD ENDING	IN (OUT) SERVICE DATE
	BALANCE JANUARY 1, 1995				33,938,744.33			
	MAJOR ADDITIONS							
4501	Purchase 10 1992 Chevy Fleetside 3/4 ton CNG Pick-ups	130,106.55				12-93	2-95	Various
4816	Install Main/Services - Richmond Lake	214,156.73				6-94	11-94	11-94
4961	Install Main/Services - Revillo	153,709.02				4-94	12-94	7-94
4962	Install Main/Services - Good/Kranz	398,978.94				6-94	12-94	8-94
5710	Purchase Meters & Regs for SD	356,576.76				2-95	12-95	Various
5758	Purchase Vermeer Flextrac	109,710.00				1-95	1-95	1-95
	MAJOR RETIREMENTS							
4447	Huron Peaking Plant		(172,622.49)			5-94	10-94	6-95
	MINOR ADDITIONS							
	SPECIFIC WORK ORDERS (43)	950,802.70				Various	Various	Various
	PERMANENT WORK ORDERS	127,818.64				Various	Various	Various
	MINOR RETIREMENTS							
	SPECIFIC WORK ORDERS (6)		(47,717.34)			Various	Various	Various
	PERMANENT WORK ORDERS		(78,170.51)			Various	Various	Various
	CORRECTIONS OR TRANSFERS			(50,567.90)				
106	COMPLETED CONSTRUCTION NOT CLASSIFIED							
	DECEMBER 31, 1995 TEST YEAR TOTALS	2,471,921.34	(298,510.34)	(50,567.90)				
	BALANCE DECEMBER 31, 1995				36,061,587.43			

NWPS
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
1994 CALENDAR YEAR
DECEMBER 31, 1994 TEST YEAR
SCHEDULE D-4
PAGE 4 OF 8

NO.	WORK ORDER DESCRIPTION	AMOUNT ADDITION	RETIREMENT	OTHER TRANSACTION	BALANCE	MAJOR ADDITIONS AND RETIREMENTS CONSTRUCTION PERIOD BEGINNING	CONSTRUCTION PERIOD ENDING	IN (OUT) SERVICE DATE
	BALANCE JANUARY 1, 1994				$30,402,242.00			
	MAJOR ADDITIONS							
3364	Install Main & Services Milbank Taps	213,141.81				9-92	12-93	9-92
4135	Install High Pressure Line to Scotland	1,105,385.91				3-93	11-93	7-93
4145	Install High Pressure Line to Parker	463,575.00				5-93	1-94	8-93
4538	Purchase Meters and Regulators	152,669.81				2-94	12-94	Various
	MAJOR RETIREMENTS							
	MINOR ADDITIONS							
	SPECIFIC WORK ORDERS (136)	1,322,886.19				Various	Various	Various
	PERMANENT WORK ORDERS	109,834.36				Various	Various	Various
	MINOR RETIREMENTS							
	SPECIFIC WORK ORDERS (22)		(78,051.46)			Various	Various	Various
	PERMANENT WORK ORDERS		(15,295.27)			Various	Various	Various
	CORRECTIONS OR TRANSFERS			67,197.98				
106	COMPLETED CONSTRUCTION NOT CLASSIFIED							
	MAJOR ADDITIONS							
4263	Install New Peaking Plant-Huron	195,159.00				6-93	12-93	11-93
	DECEMBER 31, 1994 TEST YEAR TOTALS	3,562,651.08	(93,346.73)	67,197.98				
	BALANCE DECEMBER 31,1994				33,938,744.33			

NORTHWESTERN PUBLIC SERVICE COMPANY
PLANT ACCOUNT FOR TEST YEAR - GAS - SOUTH DAKOTA
DECEMBER 31, 1993 TEST YEAR

Line No.	Account No.	Work Order Description	Amount Addition	Amount Retirement	Other Transactions	Balance	Major Additions and Retirements Construction Period Beginning	Construction Period Ending	In (Out) Service Date
1		Balance January 1, 1993				$ 25,555,960			
2		Major Additions (4)							
3		High Pressure Expansion Pipeline-Mitchell to Parkston	$ 609,266				5-91	10-91	12-93
4		Extend Main/Services to the Prairiewood House Area-Aberdeen	134,747				6-92	11-93	12-93
5		Purchase Meters & Regulators for Expansion Projects	243,596				4-93	11-93	Various
6		Install Distribution System in Warner	210,499				4-93	11-93	12-93
7		Major Retirements							
8		None							
9		Minor Additions							
10		Specific Work Orders (98)	441,881				Various	Various	Various
11		Permanent Work Orders	124,671				Various	Various	Various
12		Minor Retirements							
13		Specific Work Orders (24)		$ 63,513			Various	Various	Various
14		Permanent Work Orders		12,823			Various	Various	Various
15		Corrections or Transfers			$ 644				
16	106	Completed Construction Not Classified							
17		Major Additions (11)							
18		High Pressure Expansion Pipeline to Castlewood and Estelline							
19		and Clear Lake-Milbank-Big Stone City	125,924				1-92	12-93	12-93
20		Install Distribution System in Clear Lake	380,823				1-92	12-92	12-92
21		Install Distribution System in Mt Vernon	176,477				5-93	11-93	12-93
22		Install Distribution System in Tripp	207,326				4-93	11-93	12-93
23		Install Distribution System in Scotland	271,332				3-93	11-93	12-93
24		Install Distribution System in Menno	169,722				4-93	11-93	12-93
25		Install Distribution System in Parker	287,640				4-93	11-93	12-93
26		Install Distribution System in Marion	101,599				6-93	11-93	12-93
27		Install Distribution System in Canistota	141,287				5-93	11-93	12-93
28		Install New Peaking Plant-Huron	762,240				9-93	12-93	12-93
29		Install Distribution System in Glendale & Spink Colonies	149,462				6-93	12-93	12-93
30		Minor Additions (17)	364,260				Various	Various	12-93
31		December 31, 1993 Test Year Totals	$ 4,921,774	$ 76,336	$ 644				
32		Balance December 31, 1993				$ 30,402,242			

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS ON CAPITALIZING INTEREST
AND OTHER OVERHEADS DURING CONSTRUCTION
DECEMBER 31, 1998 TEST YEAR

Allowance for Funds Used During Construction (AFUDC)

AFUDC is computed on projects exceeding $10,000 which are under construction more then thirty days with the exception of land and land rights and blanket or permanent work orders. AFUDC, when applicable, is computed on the previous month balance plus one half of the current month expenditures excluding AFUDC since last compounding date. At six month intervals AFUDC charged is added to the balance of the project and this becomes the basis for computing AFUDC for the next six months. The semi annual compounding is allowed under the same FERC order which prescribes the formula for computing the rate. Capitalization of AFUDC ceases when the project is placed in service. The rate of AFUDC applicable to debt and other funds is calculated in accordance with the formula prescribed by the FERC.

Engineering and Supervision

Engineering and supervision expense includes payroll costs, as determined by a periodic time study, applicable to operations, engineering and supervisory personnel, not directly chargeable to specific jobs; such as budget preparation and planning, material ordering, general supervision, completion reporting, etc. These expenses are capitalized in relationship to the amount of direct construction payroll charges on a monthly basis.

Administrative and General Expense

Administrative and general expense represents the amount of compensation and related expenses of administrative staff applicable to construction activity. Administrative and general salaries chargeable to construction are determined through a periodic time study. Administrative and general overheads are capitalized in relationship to the amount of direct construction payroll charges on a monthly basis.

The portion of employee benefit expenses (account 926) allocable to construction are capitalized in relationship to the amount of direct and supervisory labor charged to construction.

NORTHWESTERN PUBLIC SERVICE COMPANY
CHANGES IN INTANGIBLE PLANT WORKING PAPERS
DECEMBER 31, 1998 TEST YEAR

Line No.		
1	Changes in Intangible Plant	None

Schedule D-7

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS ON PLANT IN SERVICE NOT USED AND USEFUL
DECEMBER 31,1998 TEST YEAR

Line No.		
1	Plant in Service not Used and Useful	None

NORTHWESTERN PUBLIC SERVICE COMPANY
ELECTRIC PROPERTY RECORDS WORKING PAPERS
DECEMBER 31,1998 TEST YEAR

Property Records and Retirement Procedures

Production: Detailed ledgers are maintained by plant, which show dates and cost of installations. When property constituting a retirement unit is removed or replaced, the original cost, as determined from the detail ledger record, is removed from plant and related accumulated depreciation accounts. Cost of removal, if any, and salvage are charged and credited respectively to the accumulated depreciation account. Salvageable materials are returned to stock at current market prices.

Transmission: Detailed ledgers are maintained by lines and substations. Such records and retirement procedures are the same as those applicable to production plant as explained above.

Distribution: Detailed ledgers are maintained for distribution lines and substations by location. Retirement procedures for lines and substations are the same as those applicable to production plant as explained above.

For mass distribution property, retirements for which installation dates are reasonably ascertainable, retirement prices are determined by reference to specific work order installations within the applicable location and time period. In the rare instances when installation dates cannot be reasonably ascertained, retirements are priced by engineering estimates. Recording procedures for retirements of such properties are the same as those applicable to plant within other functional classifications as previously explained.

General: Units of property included in general plant are identifiable on company plant records. Retirement accounting procedures are the same for general plant as previously explained as applicable to other functional classifications.

Retirement Units: The Company has adopted the list of units of property as prescribed by the Federal Energy Regulatory Commission effective January 1, 1961.

NORTHWESTERN PUBLIC SERVICE COMPANY
GAS PROPERTY RECORDS WORKING PAPERS
DECEMBER 31,1998 TEST YEAR

Property Records and Retirement Procedures

Production: Detailed ledgers are maintained by plant, which show dates and cost of installations. When property constituting a retirement unit is removed or replaced, the original cost, as determined from the detail record, is removed from plant and related accumulated depreciation accounts. Cost of removal and salvage, if any, are charged and credited respectively to the accumulated depreciation account. Salvageable materials are returned to stock at current market prices.

Distribution: Detailed ledgers are maintained for regulator stations and town border stations by location. Detailed ledgers are maintained for distribution pipelines and customer services by town. Metering and regulating ledgers are maintained by Division identification. Retirement procedures for this type of plant are the same as those applicable to production plant as explained above.

For mass distribution property not detailed by ledger, retirements for which installation dates are reasonably ascertainable, retirement prices are determined by reference to specific work order installations within the applicable location and time period. Recording procedures for retirements of such properties are the same as those applicable to plant within other functional classifications as previously explained.

General: Units of property included in general plant are identifiable on company plant records. Retirement accounting procedures are the same for general plant as previously explained as applicable to other functional classifications.

Retirement Units: The Company has adopted the list of units of property as prescribed by the Federal Energy Regulatory Commission.

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR PLANT ACQUIRED FOR WHICH REGULATORY APPROVAL HAS NOT BEEN OBTAINED
DECEMBER 31, 1998 TEST YEAR

Line No.		
1	Operating Units or Systems Acquired	
2	Without Regulatory Approval	None

THERE ARE MULTIPLE WORKSHEETS IN B:A1, C:A1, D:A1, E:A1, F:A1, G:A1, H:A1, I:A1, J:C1 K:C1, L:C1

NWPS CO.
ACCUMULATED DEPRECIATION - GAS - SOUTH DAKOTA
FUNCTIONAL ACCUMULATED DEPRECIATION
STATEMENT E
DECEMBER 31, 1998 TEST YEAR

	ACCUMULATED DEPRECIATION				ACCUMULATE	
MONTH/YEAR	PRODUCTION	DISTRIBUTION	GENERAL	UNDISTRIBUTED	AMORTIZATIO	TOTAL
December, 1997	534,855	12,753,184	429,023	(72,171)	[illegible]	13,645,038
January, 1998	538,182	12,847,230	418,783	(14,724)	[illegible]	13,789,642
February	541,509	12,950,254	386,564	248	[illegible]	13,878,771
March	544,836	13,046,776	429,770	(43,982)	[illegible]	13,977,640
April	548,163	13,144,155	426,666	(89,800)	[illegible]	14,029,428
May	551,490	13,241,585	435,475	(103,264)	[illegible]	14,125,554
June	554,817	13,338,964	445,304	(42,365)	[illegible]	14,297,013
July	558,144	13,439,012	443,284	(114,024)	[illegible]	14,326,734
August	561,471	13,438,893	432,457	(81,103)	[illegible]	14,352,060
September	564,798	13,538,630	453,821	(76,853)	[illegible]	14,480,663
October	568,125	13,572,852	473,414	(84,147)	[illegible]	14,530,672
November	571,452	13,672,317	483,349	(86,695)	[illegible]	14,640,912
December, 1998	574,779	13,769,049	481,095	(92,977)	[illegible]	14,732,494
TOTAL	7,212,621	172,752,800	5,739,005	(901,836)	[illegible]	184,806,619
THIRTEEN MONTH AVERAGE	554,817	13,288,677	441,462	(69,372)	[illegible]	14,215,894

Statement F

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING CAPITAL
DECEMBER 31, 1998 TEST YEAR

Line No.		Amount
1	Working Capital	
2	Cash Working Capital	None Claimed

Schedule F-1

NORTHWESTERN PUBLIC SERVICE COMPANY
MONTHLY BOOK BALANCES FOR MATERIALS AND SUPPLIES
FUEL STOCK AND PREPAYMENTS
DECEMBER 31, 1998 TEST YEAR

Line No.		1997	1998										
		December	January	February	March	April	May	June	July	August	September	October	November	December
1	Materials and Supplies (154, 155,156, 163)													
2	Electric:													
3	Plant and Line Material	$ 3,135,917	$ 3,059,282	$ 2,965,098	$ 2,942,085	$ 3,040,413	$ 3,105,084	$ 3,152,971	$ 3,126,485	$ 3,101,750	$ 3,098,031	$ 3,093,923	$ 3,094,533	$ 2,771,437
4	Stores Expense-Undistributed	568,074	552,313	615,639	617,309	642,193	637,979	641,268	568,400	501,015	472,764	586,991	616,551	966,768
5	Total Electric	3,703,991	3,611,595	3,580,737	3,559,394	3,682,606	3,743,063	3,794,239	3,694,885	3,602,765	3,570,795	3,680,914	3,711,084	3,738,205
6	Gas-Nebraska:													
7	Gas Materials	294,862	163,668	170,070	161,634	148,901	158,792	154,222	169,715	172,441	173,992	171,447	158,076	134,658
8	Stores Expense-Undistributed	21,987	227	508	1,011	1,407	1,790	2,316	2,687	3,430	4,300	5,885	6,168	6,924
9	Total Gas-Nebrasla	316,849	163,895	170,578	162,645	150,308	160,582	156,538	172,402	175,871	178,292	177,332	164,244	141,582
10	Gas-South Dakota:													
11	Gas Materials	426,384	548,284	563,477	566,336	562,994	600,465	621,225	582,065	694,228	688,211	654,106	651,959	609,489
12	Stores Expense-Undistributed	122,182	158,575	192,519	197,425	192,500	197,465	200,518	168,797	179,761	170,986	201,561	210,108	371,990
13	Total Gas-South Dakota	548,566	706,859	755,996	763,761	755,494	797,930	821,743	750,862	873,989	859,197	855,667	862,097	981,479
14	Other:													
15	Other Materials & Supplies	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884	183,884
16	Merchandise	222,395	239,704	14,504	23,042	22,924	18,291	18,359	18,871	19,866	21,256	21,599	22,900	22,909
17	Stores Expense-Undistributed	63,733	69,327	4,955	8,032	7,838	6,015	5,926	5,473	5,144	5,281	6,656	7,380	13,982
18	Total Other	470,012	492,915	203,343	214,958	214,646	208,190	208,169	208,228	208,894	210,421	212,139	214,164	220,775
19	Total Company	$ 5,039,418	$ 4,975,264	$ 4,710,654	$ 4,700,758	$ 4,803,054	$ 4,909,765	$ 4,980,689	$ 4,826,377	$ 4,861,519	$ 4,818,705	$ 4,926,052	$ 4,951,589	$ 5,082,041
20	Fuel Stock (151)													
21	Electric													
22	Coal -Big Stone	810,938	779,730	815,142	796,105	785,481	782,846	736,864	772,847	796,957	811,649	698,239	818,910	805,988
23	-Coyote	186,503	177,164	183,664	185,595	174,407	131,238	140,325	136,413	136,413	138,691	132,095	147,241	153,556
24	-Neal #4	235,752	220,881	218,059	246,275	184,334	150,448	173,815	144,707	147,307	179,857	200,706	284,629	428,934
25	Oil -Big Stone	14,004	41,342	38,426	37,100	36,972	33,477	30,069	29,234	29,234	27,341	25,210	23,252	52,420
26	-Coyote	8,216	6,277	8,776	8,936	8,296	7,947	6,424	8,878	8,878	7,642	9,245	7,908	9,165
27	-Neal #4	8,494	7,269	7,084	6,729	14,604	14,216	12,785	12,296	12,296	11,964	11,493	10,680	4,865
28	-Other	257,471	253,111	254,347	251,869	250,489	243,060	226,412	194,152	209,884	211,034	207,210	205,515	218,247
29	Other-Big Stone	0	0	648	769	965	723	644	643	643	476	0	0	0
30	-Coyote	959	947	947	947	947	947	947	947	947	947	947	947	947
31	Total Electric	1,522,337	1,486,741	1,527,093	1,534,325	1,456,495	1,364,902	1,328,285	1,300,117	1,342,559	1,389,601	1,285,145	1,499,082	1,674,123
32	Gas-Propane:													
33	Total Nebraska	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087	83,087
34	Total-South Dakota	224,775	224,267	223,675	223,400	222,461	222,461	222,461	222,461	222,461	222,461	222,461	222,461	221,987
35	Total Company	$ 1,830,199	$ 1,794,095	$ 1,833,855	$ 1,840,812	$ 1,762,043	$ 1,670,450	$ 1,633,833	$ 1,605,665	$ 1,648,107	$ 1,695,149	$ 1,590,693	$ 1,804,630	$ 1,979,197
36	Gas-Stored Underground (164)													
37	Total Nebraska	626,584	544,759	387,108	416,305	124,723	0	0	182,097	414,121	637,601	811,239	963,518	871,908
38	Total South Dakota	1,127,205	803,607	501,523	261,058	93,962	0	276,022	592,938	788,262	1,015,976	1,252,202	1,231,570	1,184,485
39	Total Company	$ 1,753,789	$ 1,348,366	$ 888,631	$ 677,363	$ 218,685	$ 0	$ 276,022	$ 775,035	$ 1,202,383	$ 1,653,577	$ 2,063,441	$ 2,195,088	$ 2,056,393
40	Prepayments (165)													
41	Prepaid Insurance	1,193,729	1,218,858	1,038,643	858,805	683,686	503,818	889,255	1,745,361	1,593,985	1,654,855	1,836,395	1,522,079	1,319,345
42	Other Prepaid	4,655,407	4,430,308	4,330,334	4,412,902	4,707,017	5,048,359	5,115,718	5,189,923	5,032,319	4,955,829	4,989,718	5,082,280	5,458,142
43	Total Company	$ 5,849,136	$ 5,649,166	$ 5,368,977	$ 5,271,707	$ 5,390,7[illegible]	$ 5,552,207	$ 6,004,973	$ 6,935,284	$ 6,626,304	$ 6,610,684	$ 6,826,113	$ 6,604,359	$ 6,777,487

Schedule F-2

NORTHWESTERN PUBLIC SERVICE COMPANY
MATERIALS AND SUPPLIES - GAS - SOUTH DAKOTA
MONTHLY BALANCES FOR TWO YEARS PRECEDING TEST YEAR
DECEMBER 31, 1998 TEST YEAR

Line No.	Month	Amount
1	January, 1996	$ 425,628
2	February	461,938
3	March	459,701
4	April	487,177
5	May	498,877
6	June	506,016
7	July	499,385
8	August	508,369
9	September	485,476
10	October	505,889
11	November	499,044
12	December	530,890
13	January, 1997	$ 442,111
14	February	460,460
15	March	477,153
16	April	508,915
17	May	512,484
18	June	524,131
19	July	564,837
20	August	581,072
21	September	598,984
22	October	586,768
23	November	568,805
24	December	548,566

Schedule F-3

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING CAPITAL
DATA USED IN COMPUTING WORKING CAPITAL
DECEMBER 31, 1998 TEST YEAR

No study made to support claim for cash working capital.

NORTHWESTERN PUBLIC SERVICE COMPANY
RATE OF RETURN
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	Refer to Exhibit_(RFL-2)

NORTHWESTERN PUBLIC SERVICE COMPANY
DEBT CAPITAL
WEIGHTED AVERAGE COST OF DEBT CAPITAL
DECEMBER 31, 1998 TEST YEAR

Line No.	Title or Series	Date Of Issuance	Date Of Maturity	Interest Rate	Principal Amount Of Issue	Net Proceeds	Net Proceeds Per Unit	Amount Currently Outstanding	Net Proceeds Applicable To Amount Currently Outstanding	Cost Of Money	Annual Interest Cost	Weighted Average Cost
1	POLLUTION CONTROL OBLIGATIONS:											
2	GRANT COUNTY, SD	6/1/93	6/1/2023	5.90%	$ 6,400,000	$ 6,179,805	96.56%	$ 6,400,000	$ 6,179,805	6.11%	$ 377,600	
3	CITY OF SALIX, IA	6/1/93	6/1/2023	5.90%	4,000,000	3,779,805	94.50%	4,000,000	3,779,805	6.24%	236,000	
4	MERCER COUNTY, ND	6/1/93	6/1/2023	5.85%	7,550,000	7,329,805	97.08%	7,550,000	7,329,805	6.03%	441,675	
4	GRANT COUNTY,SD	6/1/93	6/1/2023	5.90%	3,400,000	3,179,805	93.52%	3,400,000	3,179,805	6.31%	200,600	
5	CAPITAL TRUST:											
6	8.125%	8/1/95	8/1/2023	8.125%	33,505,154	33,505,154	100.00%	33,505,154	33,505,154	8.12%	2,722,232	
	SUB DEBENTURES:											
7	7.200%	11/18/98	11/18/2028	7.200%	56,701,030	55,000,000	97.00%	56,701,030	55,000,000	7.42%	4,082,474	
	GENERAL MORTGAGE BONDS:											
8	6.99%	9/18/92	9/01/2002	6.99%	25,000,000	24,932,419	99.73%	20,000,000	24,932,419	7.01%	1,747,500	
10	7.10%	8/1/95	9/1/2005	7.10%	60,000,000	60,000,000	100.00%	60,000,000	60,000,000	7.10%	4,260,000	
10	7.00%	8/15/93	8/15/2023	7.00%	55,000,000	53,845,720	97.90%	55,000,000	53,845,720	7.15%	3,850,000	
10	6.95%	11/12/98	11/12/2028	6.95%	105,000,000	99,021,300	94.31%	105,000,000	99,021,300	7.37%	7,297,500	
11	TOTAL AT DECEMBER 31, 1993							$ 351,556,184	$ 346,773,813		$ 25,215,581	7.27%

NORTHWESTERN PUBLIC SERVICE COMPANY
DEBT CAPITAL

BOND INDENTURE PROVISIONS RELATED TO MINIMUM
INTEREST COVERAGE REQUIREMENTS
31-Dec-98

Line No.		Interest Coverage
1	1993 General Mortgage Indenture	
2	Interest Coverage (Minimum Requirements - 1 3/4x)	5.4

The Company currently has outstanding bonds issued under the 1993 General Mortgage Indenture.
The provisions of the 1993 indenture result in an increase in the amount of bonds that can be issued on the basis of bonded property as well as increased financing flexibility.

GENERAL MORTGAGE INDENTURE

AND

DEED OF TRUST

NORTHWESTERN PUBLIC SERVICE COMPANY

TO

THE CHASE MANHATTAN BANK (National Association)

Dated As Of
August 1, 1993

ARTICLE FOUR
ISSUANCE OF BONDS

Section 4.01. General.

(a) Subject to the provisions of Section 4.02, 4.03, 4.04 or 4.05, whichever may be applicable, the Trustee shall authenticate and deliver Bonds of a series, for original issue, at one time or from time to time in accordance with the Company Order referred to below, upon receipt by the Trustee of:

(i) if the terms of such series are established in an indenture supplemental hereto, the indenture supplemental hereto establishing such series;

(ii) a Company Order requesting the authentication and delivery of such Bonds and, to the extent that the terms of such Bonds shall not have been established in the indenture supplemental hereto which established such series or in a Board Resolution or in an Officer's Certificate pursuant to such supplemental indenture or Board Resolution, all as contemplated by Section 3.01, either establishing such terms or, in the case of Bonds of a series subject to a Periodic Offering, specifying procedures, acceptable to the Trustee, by which such terms are to be established (which procedures may provide for authentication and delivery pursuant to oral or electronic instructions from the Company or any agent or agents thereof, which oral instructions are to be promptly confirmed electronically or in writing);

(iii) the Bonds of such series or Tranche, executed on behalf of the Company as provided herein;

(iv) a Net Earnings Certificate showing the Adjusted Net Earnings of the Company for the period therein specified to have been not less than an amount equal to one and three-fourths (1.75) times the Annual Interest Requirements therein specified, all in accordance with the provisions of Section 1.03; *provided, however,* that the Trustee shall not be entitled to receive a Net Earnings Certificate hereunder if the Bonds of such series are to have no Stated Interest Rate prior to Maturity; and *provided, further,* that, with respect to Bonds of a series subject to a Periodic Offering, other than Bonds theretofore authenticated and delivered, (A) it shall be assumed in such Net Earnings Certificate that none of such Bonds shall have a Stated Interest Rate in excess of a maximum rate to be stated therein, and no Bonds which would have a Stated Interest Rate at the time of the initial authentication and delivery thereof in excess of such maximum rate shall be authenticated and delivered under the authority of such Net Earnings Certificate, and (B) the Trustee shall be entitled to receive such Net Earnings Certificate only once, at or prior to the time of the first authentication and delivery of the Bonds of such series (unless the Company Order requesting the authentication and delivery of such Bonds is delivered on or after the date which is two years after the most recent Net Earnings Certificate with respect to such series was delivered pursuant to this clause (iv), in which case this subclause (B) shall not apply);

Section 1.03. Net Earnings Certificate; Adjusted Net Earnings; Annual Interest Requirements.

A "*Net Earnings Certificate*" means a certificate signed by an Authorized Executive Officer and an accountant (who may be an officer or employee of the Company), stating:

(a) the "*Adjusted Net Earnings*" of the Company for a period of twelve (12) consecutive calendar months within the eighteen (18) calendar months immediately preceding the first day of the month in which the Company Order requesting the authentication and delivery under this Indenture of Bonds is delivered to the Trustee, specifying:

(i) its operating revenues (which may include revenues of the Company subject when collected or accrued to possible refund at a future date);

(ii) its operating expenses, excluding (A) expenses for taxes on income or profits and other taxes measured by, or dependent on, net income, (B) provisions for reserves for renewals, replacements, depreciation, depletion or retirement of property (or any expenditures therefor), or provisions for amortization of property, (C) expenses or provisions for interest on any indebtedness of the Company, for the amortization of debt discount, premium, expense or loss on reacquired debt, for any maintenance and replacement, improvement or sinking fund or other device for the retirement of any indebtedness, or for other amortization, (D) expenses or provisions for any non-recurring charge to income or to retained earnings of whatever kind or nature (including without limitation the recognition of expense or impairment due to the non-recoverability of assets or expense), whether or not recorded as a non-recurring charge in the Company's books of account, and (E) provisions for any refund of revenues previously collected or accrued by the Company subject to possible refund;

(iii) the amount remaining after deducting the amount required to be stated in such certificate by clause (ii) above from the amount required to be stated therein by clause (i) above;

(iv) its other income, which amount may include any portion of the allowance for funds used during construction and other deferred costs (or any analogous amounts) which is not included in "other income" (or any analogous item) in the Company's books of account; and

(v) the Adjusted Net Earnings of the Company for such period of twelve (12) consecutive calendar months (being the sum of the amounts required to be stated in such certificate by clauses (iii) and (iv) above); and

(b) the "*Annual Interest Requirements*", being the interest requirements for one year, at the respective Stated Interest Rates, if any, borne prior to Maturity, upon:

(i) all Bonds Outstanding hereunder at the date of such certificate, except any for the payment or redemption of which the Bonds applied for are to be issued; *provided, however,* that, if Outstanding Bonds of any series bear interest at

a variable rate or rates, then the interest requirement on the Bonds of such series shall be determined by reference to the rate or rates in effect on the day immediately preceding the date of such certificate;

(ii) all Bonds then applied for in pending applications for new Bonds, including the application in connection with which such certificate is made; *provided, however,* that if Bonds of any series are to bear interest at a variable rate or rates, then the interest requirement on the Bonds of such series shall be determined by reference to the rate or rates to be in effect at the time of the initial authentication and delivery of such Bonds; and *provided, further,* that the determination of the interest requirement on Bonds of a series subject to a Periodic Offering shall be further subject to the provisions of clause (iv) of Section 4.01(a);

(iii) all Class "A" Bonds Outstanding under Class "A" Mortgages at the date of such certificate, except any Pledged Bonds and except any for the payment or redemption of which the Bonds applied for are to be issued; *provided, however,* that, if the Outstanding Class "A" Bonds of any series bear interest at a variable rate or rates, then the interest requirement on the Class "A" Bonds of such series shall be determined by reference to the rate or rates in effect on the day immediately preceding the date of such certificate; and

(iv) the principal amount of all other indebtedness (except (A) Pledged Bonds, (B) industrial development revenue bonds issued with respect to air or water pollution control, sewage or solid waste disposal, or other similar facilities of the Company to the extent that any other indebtedness of the Company issued to support the repayment of such indebtedness is included in Annual Interest Requirements pursuant to one of the other clauses of this definition, and (C) indebtedness for the payment of which the Bonds applied for are to be issued and indebtedness secured by a Prepaid Lien prior to the Lien of this Indenture upon property subject to the Lien of this Indenture), outstanding on the date of such certificate and secured by Lien prior to the Lien of this Indenture upon property subject to the Lien of this Indenture, if such indebtedness has been issued, assumed or guaranteed by the Company or if the Company customarily pays the interest upon the principal thereof; *provided, however,* that if any such indebtedness bears interest at a variable rate or rates, then the interest requirement on such indebtedness shall be determined by reference to the rate or rates in effect on the day immediately preceding the date of such certificate.

In any case where a Net Earnings Certificate is required as a condition precedent to the authentication and delivery of Bonds, such certificate shall be accompanied by a certificate signed by an Independent public accountant if the aggregate principal amount of Bonds then applied for plus the aggregate principal amount of Bonds authenticated and delivered hereunder since the commencement of the then current calendar year (other than those with respect to which a Net Earnings Certificate is not required, or with to which a Net Earnings Certificate accompanied by a certificate signed by an Independent public accountant has previously been furnished to the Trustee) is ten percent (10%) or more of the sum of (a) the principal amount of the Bonds at the time Outstanding, and (b) the principal amount of the Class "A" Bonds at the time Outstanding other than Pledged Bonds, which certificate shall provide that such Independent public accountant

has reviewed the Net Earnings Certificate and that such Independent public accountant has no knowledge that any statements in such Net Earnings Certificate are not true; but no such certificate need be signed by an Independent public accountant, as to dates or periods not covered by annual reports required to be filed by the Company, with respect to conditions precedent which depend upon a state of facts as of a date or dates or for a period or periods different from that required to be covered by such annual reports.

Section 1.04. Property Additions; Cost.

(a) *"Property Additions"* means, as of any particular time, any item, unit or element of property which at such time is owned by the Company and is subject to the Lien of this Indenture. Property Additions:

(i) need not consist of a specific or completed development, plant, betterment, addition, extension, improvement or enlargement, but may include construction work in progress and property in the process of purchase insofar as the Company shall have acquired legal title to such property, and may include the following:

(A) fractional and other undivided interests of the Company in property owned jointly or in common with other Persons, whether or not there are with respect to such property, other agreements or obligations on the part of the Company, if there is a bar against partition of such property which would preclude the sale of such property by any or all of such other Persons or the holder or holders of any lien or liens on the interest of any of such other Persons in such property, without the consent of the Company;

(B) engineering, economic, environmental, financial, geological and legal or other surveys, data processing equipment and software, preliminary to or associated with the acquisition or construction of property included or intended to be included in the Mortgaged Property, provided that any such property is not Excepted Property or, if it is Excepted Property, such property has been subjected to the Lien and operation of this Indenture as provided in Granting Clause Third;

(C) paving, grading and other improvements to, under or upon highways, bridges, parks or other public property of analogous character required for or in connection with the installation or repair of overhead, surface or underground facilities and paid for and used or to be used by the Company, notwithstanding that the Company may not hold legal title thereto;

(D) property located over, on or under property owned by other Persons, including governmental or municipal agencies, bodies or subdivisions, under permits, licenses, easements, franchises and other similar privileges, if the Company shall have the right to remove the same;

NORTHWESTERN PUBLIC SERVICE COMPANY
PREFERRED STOCK CAPITAL
WEIGHTED AVERAGE COST OF PREFERRED STOCK CAPITAL
DECEMBER 31, 1998 TEST YEAR

Line No.	Title	Date of Issuance	Call Price	Terms Of Conversion	Dividend Rate	Amount of Issue Par Or Stated Value	Price To Public Per Share	Gross Proceeds	Underwriters' Discount Or Commission	
									Amount	Percent of Gross Proceeds
1	Preferred Stock (1)									
2	4 1/2% Series	February 1947	$100.00	None	4.5%	$ 600,000	$107.00	$2,699,421	$113,391	4.20%
3	6 1/2% Series	November 1995	100.00 (2)	None	6.50%	1,150,000	100.00 (3)	1,150,000	N/A	N/A

Line No.	Title	Issuance Expenses		Net Proceeds	Net Proceeds Per Unit	Cost of Money (Dividend Rate Divided By Net Proceeds Per Unit)	Amount Outstanding	Annual Cost	Weighted Average Cost	Issue Offered To Stockholders Through Rights Or To Public
		Amount	Percent of Gross Proceeds							
4	Preferred Stock									
5	4 1/2% Series	$18,714	0.69	$2,567,316	$98.74	4.56%	$2,600,000	$117,000		Public
6	6 1/2% Series	N/A	N/A	1,150,000	100.00	6.50%	1,150,000	74,750		Stockholders
	Total at December 31, 1998						$3,750,000	$191,750	3.25%	

Note:

(1) No issue of the Company's Cumulative Preferred Stock is owned by an affiliate.

(2) Non - callable for ten years from date of insurance.

(3) Shares were issued to the former stockholders of Myers Propane.

NORTHWESTERN PUBLIC SERVICE COMPANY
COMMON STOCK CAPITAL
SALES OF COMMON STOCK DURING FIVE YEAR PERIOD
PRECEDING THE MOST RECENTLY AVAILABLE BALANCE SHEET
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	None

Schedule G-1

NORTHWESTERN PUBLIC SERVICE COMPANY
STOCK DIVIDENDS, STOCK SPLITS OR CHANGES IN PAR OR STATED VALUE TRANSACTIONS DURING FIVE YEAR PERIOD PRECEDING THE DATE OF THE MOST RECENTLY AVAILABLE BALANCE SHEET AND BY MONTHS FOR THE TEST PERIOD PLUS SUBSEQUENT MONTHS AS AVAILABLE
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	In May 1997, stockholders approved a two-for-one split in the Company's common stock effective May 19,1997.

Schedule G-2

NORTHWESTERN PUBLIC SERVICE COMPANY
COMMON STOCK INFORMATION
DATA FOR FIVE CALENDAR YEARS PRECEDING THE
END OF THE TEST PERIOD AND BY MONTH
FOR THE TWELVE MONTHS OF THE TEST PERIOD
DECEMBER 31, 1998 TEST YEAR

Line No.		Average Number of Shares Outstanding*	Earnings Per Average Share for Five Years Preceding the Test Year*	Annual Earnings Per Share for the Latest Reported Twelve Month Average	Annual Dividend Rate Per Share*	Dividends as a Percent of Earnings	Average Market Price Based on Monthly High and Low*	Price Earnings Ratio	Price Dividend Ratio
1	1994	15,354,464	$1.00		$0.85	85.00%	$13.53	13.53	15.92
2	1995	16,261,162	1.11		0.88	79.28%	13.16	11.86	14.95
3	1996	17,840,244	1.28		0.92	71.88%	15.82	12.36	17.20
4	1997	17,842,511	1.31		0.97	74.05%	20.22	15.44	20.85
5	1998	18,659,818	1.45		1.03	71.03%	23.82	16.43	23.13
6	January, 1998	17,842,704	-	$1.28	0.97	75.78%	22.63	17.68	23.33
7	February, 1998	17,842,742	-	1.26	0.97	75.78%	22.41	17.51	23.10
8	March, 1998	17,842,524	-	1.34	0.97	72.39%	23.25	17.35	23.97
9	April, 1998	17,842,524	-	1.39	0.97	69.78%	21.75	15.65	22.42
10	May, 1998	17,842,524	-	1.40	0.97	69.29%	23.47	16.76	24.20
11	June, 1998	17,842,524	-	1.35	0.97	71.85%	24.22	17.94	24.97
12	July, 1998	17,842,633	-	1.40	0.97	69.29%	25.85	18.46	26.65
13	August, 1998	17,842,320	-	1.42	0.97	68.31%	24.82	17.48	25.59
14	September, 1998	17,846,944	-	1.40	0.97	69.45%	26.07	18.62	26.81
15	October, 1998	17,854,691	-	1.38	1.03	74.64%	25.00	18.12	24.27
16	November, 1998	18,222,104	-	1.38	1.03	74.64%	23.85	17.28	23.16
17	December, 1998	18,659,818	-	1.45	1.03	70.64%	25.00	17.22	24.27

* Adjusted for the two-for-one stock split in May 1997

SCHEDULE G-3

NORTHWESTERN PUBLIC SERVICE COMPANY
REACQUISITION OF BONDS OR PREFERRED STOCK
DATA FOR EIGHTEEN MONTHS PRIOR TO FILING
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	None

Schedule G-4

NORTHWESTERN PUBLIC SERVICE COMPANY
EARNINGS PER SHARE FOR CLAIMED RATE OF RETURN
DECEMBER 31, 1998 TEST YEAR

Line No.		Total Company (Per Books)	Pro Forma Adjustments (TPH-1) Sch No. 1	Total Company (Adjusted)
1	Consolidated Earnings to Common	$ 27,086,563	$ 2,295,237	$ 29,381,800
2	Average Common Shares Outstanding	18,659,818	-	18,659,818
3	Earnings Per Share of Common Stock	$ 1.45	$ -	$ 1.57

NORTHWESTERN PUBLIC SERVICE COMPANY
OPERATION AND MAINTENANCE EXPENSES - GAS - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 1998 TEST YEAR

Line No.	No.	Description	1998 January	February	March	April	May	June	July	August
1		MANUFACTURED GAS PRODUCTION								
2		Operation:								
3	710	Supervision & Engineering	$ 1,040	$ 1,052	$ 1,248	$ 1,039	$ 1,041	$ 1,109	$ 1,202	$ 1,136
4	717	Liquefied Petroleum Gas Expenses	17	0	0	0	22	0	19	253
5	723	Fuel for Liquefied Petroleum Gas Process	508	460	276	938	0	0	0	0
6	728	Liquefied Petroleum Gas	0	132	0	0	0	0	0	0
7	735	Miscellaneous Production Expenses	253	262	143	103	70	367	168	153
8		Total Operation	1,818	1,906	1,667	2,080	1,133	1,476	1,389	1,542
9		Maintenance:								
10	740	Maintenance Supervision & Engineering	756	920	896	755	759	805	897	821
11	741	Maintenance of Structures	0	0	0	0	0	0	0	26
12	742	Maintenance of Production Equipment	129	821	961	613	234	173	0	344
13		Total Maintenance	885	1,741	1,857	1,368	993	978	897	1,191
14		Total Manufacured Gas Production	2,703	3,647	3,524	3,448	2,126	2,454	2,286	2,733
15		OTHER GAS SUPPLY								
16	804	Natural Gas City Gate Purchases *	3,750,064	3,104,435	2,933,933	2,397,395	892,300	489,299	402,628	306,920
17		DISTRIBUTION								
18		Operation:								
19	870	Supervision & Engineering	88,795	64,592	36,425	60,583	72,228	60,606	37,466	37,849
20	871	Load Dispatching	6,964	12,014	10,491	10,042	11,755	4,347	7,683	10,150
21	874	Mains & Services Expenses	26,007	36,990	49,811	30,090	31,079	40,808	38,514	41,452
22	875	Measuring & Regulating Station Expenses - General	1,372	994	1,320	1,135	3,071	1,331	2,115	777
23	877	Measuring & Regulating Station Expenses - City Gate	3,816	3,662	4,171	3,801	2,841	4,795	3,232	2,371
24	878	Meters & House Regulator Expenses	21,014	7,267	35,418	31,246	17,866	(2,547)	22,300	20,265
25	879	Customers Installation Expenses	(16,517)	(27,569)	(10,793)	(2,510)	(39,902)	11,229	(13,826)	(7,048)
26	880	Other Expenses	27,459	35,815	34,836	24,430	20,247	22,708	18,768	20,273
27	881	Rents	124	109	1,631	110	109	109	109	109
28		Total Operation	161,034	133,874	163,310	158,927	119,294	143,386	116,361	126,198
29		Maintenance:								
30	885	Maintenance Supervision & Engineering	5,721	5,559	5,492	5,292	5,062	4,862	5,073	4,764
31	886	Maintenance of Structures	6	0	0	0	0	0	84	0
32	887	Maintenance of Mains	1,417	4,304	5,482	2,559	2,340	3,042	3,429	2,437
33	889	Maintenance of Measuring & Reg Sta Equip - General	2,581	773	1,215	2,165	3,523	278	226	215
34	891	Maintenance of Measuring & Reg Sta Equip - City Gate	241	150	77	65	0	623	60	118
35	892	Maintenance of Services	2,367	4,890	4,031	4,715	5,720	3,411	3,862	2,536
36	893	Maintenance of Meters & House Regulators	15,442	13,365	17,117	10,903	6,561	7,131	7,771	7,673
37		Total Maintenance	27,775	29,041	33,414	25,699	23,206	19,347	20,505	17,743
38		Total Distribution Expenses	$ 188,809	$ 162,915	$ 196,724	$ 184,626	$ 142,500	$ 162,733	$ 136,866	$ 143,941

* Includes Deferred Gas Cost Adjustments

NORTHWESTERN PUBLIC SERVICE COMPANY
OPERATION AND MAINTENANCE EXPENSES - GAS - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 1998 TEST YEAR

Line No.	No.	Description	1998 September	1998 October	1998 November	1998 December	1998 Total	Pro Forma Adjustments	Adjusted Amount
1		MANUFACTURED GAS PRODUCTION							
2		Operation:							
3	710	Supervision & Engineering	$ 1,232	$ 1,173	$ 1,174	$ 957	$ 13,403	$ 144	$ 13,547
4	717	Liquefied Petroleum Gas Expenses	0	0	134	0	445	13	458
5	723	Fuel for Liquefied Petroleum Gas Process	0	0	0	474	2,656	0	2,656
6	728	Liquefied Petroleum Gas	0	0	0	0	132	(132)	0
7	735	Miscellaneous Production Expenses	71	224	28	116	1,958	28	1,986
8		Total Operation	1,303	1,397	1,336	1,547	18,594	53	18,647
9		Maintenance:							
10	740	Maintenance Supervision & Engineering	889	850	850	939	10,137	122	10,259
11	741	Maintenance of Structures	42	0	0	0	68	2,237	2,305
12	742	Maintenance of Production Equipment	0	0	179	128	3,582	(2,171)	1,411
13		Total Maintenance	931	850	1,029	1,067	13,787	188	13,975
14		Total Manufacured Gas Production	2,234	2,247	2,365	2,614	32,381	241	32,622
15		OTHER GAS SUPPLY							
16	804	Natural Gas City Gate Purchases *	292,776	657,551	1,756,195	2,232,441	19,215,937	3,578,969	22,794,906
17		DISTRIBUTION							
18		Operation:							
19	870	Supervision & Engineering	48,420	57,144	(164,528)	32,511	432,091	4,620	436,711
20	871	Load Dispatching	13,015	10,814	10,429	11,277	120,981	(5,736)	115,245
21	874	Mains & Services Expenses	19,527	44,132	31,281	33,534	423,225	3,324	426,549
22	875	Measuring & Regulating Station Expenses - General	578	599	857	1,371	15,520	386	15,906
23	877	Measuring & Regulating Station Expenses - City Gate	3,506	3,289	3,212	4,146	42,842	1,036	43,878
24	878	Meters & House Regulator Expenses	22,226	37,563	8,527	22,870	244,015	14,073	258,088
25	879	Customers Installation Expenses	(7,596)	(20,439)	(22,530)	(17,224)	(174,725)	15,685	(159,040)
26	880	Other Expenses	15,553	10,063	10,772	16,888	257,812	4,477	262,289
27	881	Rents	1,702	109	109	497	4,827	(326)	4,501
28		Total Operation	116,931	143,274	(121,871)	105,870	1,366,588	37,539	1,404,127
29		Maintenance:							
30	885	Maintenance Supervision & Engineering	4,923	5,392	5,130	5,380	62,650	(503)	62,147
31	886	Maintenance of Structures	0	0	0	0	90	0	90
32	887	Maintenance of Mains	1,493	1,511	1,644	3,042	32,700	494	33,194
33	889	Maintenance of Measuring & Reg. Sta. Equip. - General	854	221	90	23	12,164	333	12,497
34	891	Maintenance of Measuring & Reg. Sta. Equip. - City Gate	0	199	109	74	1,716	40	1,756
35	892	Maintenance of Services	1,469	1,770	2,156	3,270	40,197	918	41,115
36	893	Maintenance of Meters & House Regulators	6,576	9,583	6,616	(21,255)	87,483	(3,047)	84,436
37		Total Maintenance	15,315	18,676	15,745	(9,466)	237,000	(1,765)	235,235
38		Total Distribution Expenses	$ 132,246	$ 161,950	$ (106,126)	$ 96,404	$ 1,603,588	$ 35,774	$ 1,639,362

* Includes Deferred Gas Cost Adjustments and MGP Removal Cost Adjustment Amortization.

NORTHWESTERN PUBLIC SERVICE COMPANY
OPERATION AND MAINTENANCE EXPENSES - GAS - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 1998 TEST YEAR

Line No.	No.	Description	1998 January	February	March	April	May	June	July	August
1		CUSTOMER ACCOUNTS EXPENSE								
2		Operation:								
3	901	Supervision	$ 13,290	$ 12,261	$ 13,185	$ 13,648	$ 13,081	$ 13,987	$ 10,123	$ 12,591
4	902	Meter Reading Expenses	23,132	19,029	20,764	21,029	18,966	20,691	20,916	21,232
5	903	Customer Records & Collection Expenses	33,807	34,532	37,215	33,148	31,185	39,373	39,357	36,192
6	904	Uncollectible Accounts	10,728	10,621	8,984	7,353	5,831	4,819	5,227	5,157
7	905	Miscellaneous Customer Accounts Expenses	2,342	732	1,036	4,884	1,523	1,194	(86)	687
8		Total Customer Accounts Expense	83,299	77,175	81,184	80,062	70,586	80,064	75,537	75,859
9		CUSTOMER SERVICE AND INFORMATIONAL EXPENSE								
10		Operation:								
11	907	Supervision	508	693	512	566	523	566	596	594
12	908	Customer Assistance Expense	92,164	90,713	90,369	90,104	89,273	89,649	89,374	89,398
13	909	Informational & Instructional Advertising Expense	3,281	2,096	3,289	1,078	989	1,075	860	1,123
14	910	Misc. Customer Service & Informational Expense	971	3,257	825	1,148	1,395	834	905	1,540
15		Total Customer Services & Informational Expense	96,924	96,759	94,995	92,896	92,180	92,124	91,735	92,655
16		SALES EXPENSE								
17		Operation:								
18	911	Supervision	0	0	0	0	0	0	0	0
19	912	Demonstrating & Selling Expenses	0	0	0	0	0	0	0	0
20	913	Advertising Expenses	(380)	(721)	(702)	(700)	(666)	912	51	56
21	916	Miscellaneous Sales Expenses	0	0	0	0	0	0	0	0
22		Total Sales Expense	(380)	(721)	(702)	(700)	(666)	912	51	56
23		ADMINISTRATIVE AND GENERAL EXPENSES								
24		Operation:								
25	920	Administrative & General Salaries	69,388	67,202	66,007	65,544	65,584	91,991	79,585	82,571
26	921	Office Supplies & Expenses	35,505	45,188	48,476	59,838	54,452	59,902	43,545	59,040
27	922	Administrative Expenses Transferred - Cr.	(32,843)	(95,709)	(48,501)	(92,443)	(73,847)	(70,560)	(46,403)	(70,777)
28	923	Outside Services Employed	23,016	31,090	28,808	28,030	26,662	19,038	17,393	20,018
29	924	Property Insurance	2,171	2,237	2,171	2,171	2,171	2,171	1,690	1,916
30	925	Injuries & Damages	9,147	8,308	7,119	6,970	6,287	7,638	6,510	6,828
31	926	Employee Pensions & Benefits	19,426	62,282	83,634	55,570	62,762	49,715	51,673	95,121
32	928	Regulatory Commission Expenses	0	0	0	0	0	0	0	0
33	930.1	General Advertising Expenses	2,888	3,110	12,816	3,071	18,997	9,450	7,510	7,696
34	930.2	Miscellaneous General Expenses	25,899	18,404	48,136	9,501	42,963	14,937	8,468	11,579
35	931	Rents	12,364	24,826	6,867	32,439	19,784	19,209	22,866	11,738
36		Total Operation	166,961	166,938	255,533	170,691	225,815	203,491	192,837	225,730
37		Maintenance								
38	932	Maintenance of General Plant	26,696	24,135	21,124	22,523	20,928	26,911	22,756	24,982
39		Total Administrative & General Expenses	193,657	191,073	276,657	193,214	246,743	230,402	215,593	250,712
40		Total Gas Operation & Maintenance Expenses	$ 4,315,076	$ 3,635,283	$ 3,586,315	$ 2,950,941	$ 1,445,769	$ 1,057,988	$ 924,696	$ 872,876

NORTHWESTERN PUBLIC SERVICE COMPANY
OPERATION AND MAINTENANCE EXPENSES - GAS - SOUTH DAKOTA
TWELVE MONTHS ENDED DECEMBER 31, 1998 TEST YEAR

Line No.	No.	Description	1998 September	October	November	December	Total	Pro Forma Adjustments	Adjusted Amount
1		CUSTOMER ACCOUNTS EXPENSE							
2		Operation:							
3	901	Supervision	$ 12,141	$ 12,358	$ 11,685	$ 10,229	$ 148,579	$ 5,478	$ 154,057
4	902	Meter Reading Expenses	20,668	21,459	19,615	25,291	252,792	6,700	259,492
5	903	Customer Records & Collection Expenses	31,181	35,773	39,576	32,880	424,219	9,372	433,591
6	904	Uncollectible Accounts	5,060	4,927	6,571	15,334	90,612	(2,018)	88,594
7	905	Miscellaneous Customer Accounts Expenses	662	383	161	1,916	15,434	(1)	15,433
8		Total Customer Accounts Expense	69,712	74,900	77,608	85,650	931,636	19,531	951,167
9		CUSTOMER SERVICE AND INFORMATIONAL EXPENSE							
10		Operation:							
11	907	Supervision	594	594	595	595	6,936	230	7,166
12	908	Customer Assistance Expense	89,133	89,318	89,289	89,276	1,078,060	(310,973)	767,087
13	909	Informational & Instructional Advertising Expense	1,136	1,147	1,141	5,986	23,201	469	23,670
14	910	Misc. Customer Service & Informational Expense	1,575	837	827	1,045	15,159	336	15,495
15		Total Customer Services & Informational Expense	92,438	91,896	91,852	96,902	1,123,356	(309,938)	813,418
16		SALES EXPENSE							
17		Operation:							
18	911	Supervision	0	0	0	0	0		0
19	912	Demonstrating & Selling Expenses	0	0	0	0	0		0
20	913	Advertising Expenses	50	51	32	59	(1,958)	1,958	0
21	916	Miscellaneous Sales Expenses	0	0	0	0	0		0
22		Total Sales Expense	50	51	32	59	(1,958)	1,958	0
23		ADMINISTRATIVE AND GENERAL EXPENSES							
24		Operation:							
25	920	Administrative & General Salaries	82,021	85,069	35,582	85,448	875,992	(76,766)	799,226
26	921	Office Supplies & Expenses	42,883	43,944	29,497	57,377	579,647	(53,785)	525,862
27	922	Administrative Expenses Transferred - Cr.	(59,605)	(75,810)	(67,616)	(87,017)	(821,221)	64,839	(756,382)
28	923	Outside Services Employed	16,276	17,429	14,140	17,597	259,497	(31,031)	228,466
29	924	Property Insurance	1,916	1,916	1,916	1,916	24,362	(1,532)	22,830
30	925	Injuries & Damages	6,550	6,891	7,819	8,105	88,172	(5,390)	82,782
31	926	Employee Pensions & Benefits	61,753	68,442	92,734	74,810	775,922	(104,862)	671,060
32	928	Regulatory Commission Expenses	0	0	0	0	0	50,000	50,000
33	930.1	General Advertising Expenses	1,289	9,966	1,833	29,535	108,161	(108,161)	0
34	930.2	Miscellaneous General Expenses	5,694	3,873	9,717	12,555	211,726	(24,821)	186,905
35	931	Rents	16,794	27,456	29,156	26,186	249,685	(13,314)	236,371
36		Total Operation	175,481	187,176	154,778	226,512	2,351,943	(304,823)	2,047,120
37		Maintenance:							
38	932	Maintenance of General Plant	23,410	28,869	20,552	21,021	283,907	(31,442)	252,465
39		Total Administrative & General Expenses	198,891	216,045	175,330	247,533	2,635,850	(336,265)	2,299,585
40		Total Gas Operation & Maintenance Expenses	$ 695,909	$ 1,204,640	$ 1,997,256	$ 2,761,603	$ 25,540,790	$ 2,990,270	$ 28,531,060

NORTHWESTERN PUBLIC SERVICE COMPANY
ADJUSTMENTS TO OPERATION AND MAINTENANCE EXPENSES
DECEMBER 31, 1998 TEST YEAR

Line No.	Description	Total	Pro Forma Adjustments	Adjusted Amount
1	Production Expenses			
2	Operation:			
3	Labor	$ 13,287	$ 190	$ 13,477
4	Other	5,308	(138)	5,170
5	Maintenance:			
6	Labor	11,178	197	11,375
7	Other	2,610	(10)	2,600
8	Total	$ 32,383	$ 239	$ 32,622
9	Distribution Expenses			
10	Operation:			
11	Labor	$ 994,703	$ 22,084	$ 1,016,787
12	Other	371,886	15,454	387,340
13	Maintenance:			
14	Labor	201,550	(1,011)	200,539
15	Other	35,455	(759)	34,696
16	Total	$ 1,603,594	$ 35,768	$ 1,639,362

NORTHWESTERN PUBLIC SERVICE COMPANY
ADJUSTMENTS TO OPERATION AND MAINTENANCE EXPENSES
DECEMBER 31, 1993 TEST YEAR

Line No.	Description	Total	Pro Forma Adjustments	Adjusted Amount
1	Customer Accounts Expense			
2	Operation:			
3	Labor	$ 674,258	$ 20,988	$ 695,246
4	Other	257,375	(1,454)	255,921
5	Total	$ 931,633	$ 19,534	$ 951,167
6	Customer Service & Informational Expenses			
7	Operation:			
8	Labor	$ 88,827	$ 2,921	$ 91,748
9	Other	1,034,531	(312,861)	721,670
10	Total	$ 1,123,358	$ (309,940)	$ 813,418
11	Sales Expenses			
12	Operation:			
13	Labor	$ (2,227)	$ 2,227	$ 0
14	Other	269	(269)	0
15	Total	$ (1,958)	$ 1,958	$ 0
16	Administrative & General Expenses			
17	Operation:			
18	Labor	$ 1,238,469	$ (123,645)	$ 1,114,824
19	Other	1,113,480	(231,183)	882,297
20	Maintenance:			
21	Labor	23,458	(1,227)	22,231
22	Other	260,450	(30,217)	230,233
23	Total	$ 2,635,857	$ (386,272)	$ 2,249,585

Schedule H-2

NORTHWESTERN PUBLIC SERVICE COMPANY
PURCHASED GAS COST
DECEMBER 31, 1998 TEST YEAR

Please Refer to Exhibit _ (TPH-1) Schedules Nos. 2 and 2.1

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
ADMINISTRATION EXPENSES TRANSFERRED - CREDIT
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Account 922 Administrative Expenses Transferred - Credit			
2	Payroll and Expenses	$ (821,221)	$ $64,839	$ (756,382)

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
EMPLOYEE PENSIONS AND BENEFITS
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Account 926 Employee Pensions and Benefits			
2	Pension Expense	$ 64,621	$ (8,733)	$ 55,888
3	VIP Plan Expense	122,211	(16,516)	105,695
4	ESOP	45,387	(6,134)	39,253
5	Health Plan Expense	237,691	(32,123)	205,568
6	Group Life Insurance	470,007	(63,519)	406,488.00
7	Transferred - Credit	(207,876)	28,093	(179,783.00)
8	Other	43,881	(5,930)	37,951
9	Total	$ 775,922	$ (104,862)	$ 671,060

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
REGULATORY COMMISSION EXPENSE
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Account 928 Regulatory Commission Expense			
2	Miscellaneous Expense	$ 0	$ $50,000	$ $50,000
3				
4	Total	$ 0	$ 50,000	$ 50,000

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
DUPLICATE CHARGES - CREDIT
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Account 929 Duplicate Charges - Credit	$ 0	$ -	$ 0

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
MISCELLANEOUS GENERAL EXPENSES
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Account 930.2 Miscellaneous General Expense			
2	Industry Association Dues	$ 25,960	(3,043)	22,917
3	Research	0	0	0
4	Reports	23,508	(2,756)	20,752
5	Stockholder's Services	46,052	(5,399)	40,653
6	Director's Expense	108,771	(12,752)	96,019
7	Development Expense	7,437	(872)	6,565
8	Other	0		0
9	Total	$ 211,728	$ (24,822)	$ 186,906

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR LISTED EXPENSE ACCOUNTS - GAS - SOUTH DAKOTA
ADVERTISING EXPENSE RECORDED IN ACCOUNTS 909, 913, AND 930
DECEMBER 31, 1998 TEST YEAR

Line No.		Per Books	Pro Forma Adjustment	Adjusted Amount
1	Classification			
2	Conservation	$ 0	$	$ 0
3	Safety	12,189		12,189
4	Informational	7,447		7,447
5	Required By Law	3,565		3,565
6	Promotional	(1,958)	1,958	0
7	Institutional	108,160	(108,160)	0
8	Rate Justification	0		0
11	Other			
12	Total	$ 129,403	$ (106,202)	$ 23,201

NORTHWESTERN PUBLIC SERVICE COMPANY
OPERATING REVENUES PER BOOKS - GAS - SOUTH DAKOTA
DECEMBER 31, 1998 TEST YEAR

REVENUE AND MCF SALES PER BOOKS

Line No		1998 January	February	March	April	May	June	July	August	September	October	November	December	Test Year Total Operating Revenues
1	Operating Revenues -													
2	Sales of Gas													
3	Residential-General	$ 3,276,222	$ 2,734,701	$ 2,544,085	$ 2,190,111	$ 980,595	$ 582,653	$ 493,727	$ 429,059	$ 418,450	$ 695,755	$ 1,538,693	$ 2,221,054	$ 18,107,008
4	Commercial & Indus-													
5	trial-Small General	1,698,319	1,529,057	1,311,971	1,037,511	463,249	255,372	259,059	197,646	199,795	307,793	752,289	1,121,591	9,133,649
6	Commercial & Indus-													
7	trial-Large Firm	0	271	66,990	75,532	12,134	2,083	1,854	1,829	1,876	2,081	2,683	3,267	170,570
8	Commercial & Indus-													
9	trial-Firm-Agency	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Commercial & Indus-													
11	trial-Interruptible	134,757	125,825	117,963	81,948	33,766	23,298	22,447	26,349	23,446	93,052	262,442	251,876	1,197,169
12	Commercial & Indus-													
13	trial-Interup-Agency	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Sales of Gas	5,111,298	4,389,857	4,040,979	3,385,102	1,489,741	863,306	777,087	654,883	643,567	1,098,681	2,556,107	3,597,788	28,608,396
15	Other Operating													
16	Revenues-													
17	Forfeited Discounts	8,234	9,518	11,252	7,762	6,834	4,529	2,995	2,144	1,943	1,482	1,661	3,711	61,856
18	Misc. Service Revenues	3,731	3,416	5,804	2,389	4,820	5,103	5,178	5,375	6,377	9,738	8,121	6,203	66,255
19	Transport Gas Billed	86,162	100,849	87,165	105,249	86,981	77,050	73,261	71,473	73,002	79,484	106,408	119,804	1,066,888
20	Other Gas Revenues	6	11	86	138	94	121	85	83	103	117	138	314	1,296
21	Total Other Operating													
22	Revenues	98,133	113,794	104,307	115,538	93,529	86,803	81,510	79,075	81,425	90,821	116,328	130,032	1,196,295
23	Total Operating Revenues	$ 5,209,431	$ 4,503,651	$ 4,145,286	$ 3,500,640	$ 1,588,270	$ 950,109	$ 858,597	$ 733,958	$ 724,992	$ 1,189,502	$ 2,672,435	$ 3,727,820	$ 29,804,691
24	MMBTU Sales													
25	Residential-General	561,131	478,620	427,651	364,727	144,924	73,891	58,988	48,756	47,300	95,750	238,791	344,344	2,885,073
26	Commercial & Indus-													
27	trial-Small-General	260,532	245,123	213,072	169,575	61,175	32,203	28,537	26,066	24,350	40,962	112,284	168,724	1,383,203
28	Commercial & Indus-													
29	trial-Large-Firm	101,006	87,283	75,920	62,013	34,164	8,345	20,626	11,357	10,947	19,344	36,633	52,907	520,747
30	Commercial & Indus-													
31	trial-Firm-Agency	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Commercial & Indus-													
33	trial-Interruptible	41,179	41,544	37,545	24,458	8,717	5,726	4,940	6,197	6,482	29,598	87,700	90,355	384,461
34	Commercial & Indus-													
35	trial-Interup-Agency	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total MMBTU Sales	963,848	852,570	754,988	620,773	248,980	120,165	113,093	92,376	89,059	185,654	475,608	656,370	5,173,484
37	Gas Transported - MMBTU	257,522	299,308	252,784	307,187	250,836	224,846	211,102	190,185	186,921	207,508	281,988	426,737	3,077,508

NORTHWESTERN PUBLIC SERVICE COMPANY

DECEMBER 31, 1998 TEST YEAR

Reference is made to Exhibit _ (TPH-1), Schedule Nos. 2,2.1,2.1a

NORTHWESTERN PUBLIC SERVICE COMPANY
DEPRECIATION EXPENSE-GAS-SOUTH DAKOTA
DECEMBER 31, 1998 TEST YEAR

Reference is made to Exhibit __ (TPH-1), Schedule No. 5

J

NORTHWESTERN PBULIC SERCICE COMPANY
EXPENSE CHARGED OTHER THAN PRESCRIBED DEPRECIATION-GAS-SOUTH DAKOTA
DECEMBER 31, 1998 TEST YEAR
SCHEDULE J-1

Q:\DATA\123\RON\RATEFILE\1998\RATEDATA

RECONCILIATION OF PLANT BALANCES ON WHICH DEPRECIATION IS CALCULATED TO PLANT IN SERVICE BALANCES 1/	1ST QUARTER DECEMBER 1997 BALANCE	2ND QUARTER MARCH 1998 BALANCE	3RD QUARTER JUNE 1998 BALANCE	4TH QUARTER SEPTEMBER 1998 BALANCE
BALANCE ON WHICH STATEMENT J DEPRECIATION IS CALCULATED	38,437,129	38,777,478	40,348,699	40,473,365
ADD: NON DEPRECIABLE PROPERTY	1,342,304	1,227,808	1,263,308	1,200,487
MISCELLANEOUS INTANGIBE PLANT	2,931	2,931	2,931	7,327
LIMITED TERM INVESTMENT AMORTIZED	0	0	0	0
TOTAL PLANT IN SERVICE BALANCE PER SCHEDULE D-3	39,782,364	40,008,217	41,614,938	41,681,179

1/ BALANCES ARE NOT RECONCILED TO STATEMENT D AS PER FILING INSTRUCTIONS AS THE COMPANY'S PROCEDURE IS TO BASE DEPRECIATION FOR A CALENDAR QUARTER UPON DEPRECIABLE PLANT IN SERVICE BALANCES AS OF THE BEGINNING OF THE QUARTER.

NOTE: DEPRECIATION CHARGED TO OTHER THAN PRESCRIBED EXPENSE ACCOUNTS IS DETAILED ON STATEMENT J.

Northwestern Public Service Company
Income Taxes as Recorded and as Adjusted
December 31, 1998 Test Year

Line No.		As Recorded South Dakota Electric	As Recorded South Dakota Gas	As Recorded Nebraska	Pro Forma Adjustments	SD Adjusted
1	Operating Revenue	$ 78,414,964	$ 29,804,685	$ 30,033,515	$ 5,960,501	$ 35,765,186
2	Operating Expenses:					
3	Operation & Maintenance	35,582,443	25,540,795	27,341,633	2,990,265	28,531,060
4	Depreciation & Amortization	11,869,516	1,665,371	1,104,708	(48,581)	1,616,790
5	Taxes Other Than Income Taxes	5,355,701	715,772	174,252	261,247	977,019
6	Total	52,807,660	27,921,938	28,620,593	3,202,931	31,124,869
7	Operating Income Before Income Taxes	25,607,304	1,882,747	1,412,922	2,757,570	4,640,317
8	Other Income - Net Before Income Taxes					
9	And Excluding AFUDC	-	-	-	-	0
10	Interest Charges:					
11	Long-Term	12,644,987	1,576,197	1,095,323	(427,924)	1,148,273
12	Amortization of Debt Discount & Expense	254,396	28,399	19,735		28,399
13	Commercial Paper	683,336	94,570	65,718		94,570
14	Customer Deposits	32,652	4,519	3,140		4,519
15	Refunds	-	0	0		0
16	Other	(25,478)	(106,957)	(74,326)		(106,957)
17	Total	13,589,893	1,596,728	1,109,590	(427,924)	1,168,804
18	Book Taxable Income	$ 12,017,411	$ 286,019	$ 303,332	$ 3,185,494	$ 3,471,513

Northwestern Public Service Company
Income Taxes as Recorded and as Adjusted
December 31, 1998 Test Year

Line No.		As Recorded South Dakota Electric	As Recorded South Dakota Gas	Nebraska Gas	Pro Forma Adjustments	SD Adjusted
1	Adjustments For Federal Tax Purposes:					
2	Depreciation	636,308	211,175	146,749		211,175
3	Non-deductible SISP premiums	416,004	138,061	95,941		138,061
4	Environmental Clean-up Amortization Reversal	351,288	116,583	81,016		116,583
5	Spousal Travel Disallowance	12,800	4,248	2,952		4,248
6	FPCSSP Premiums	446,746	148,264	103,030		148,264
7	Lobbying Expense Disallowance	44,800	14,868	10,332		14,868
8	Municipal Bond Interest					-
9	State Income Taxes - NE			(123,335)		-
10	State Income Taxes - ND	(59,618)				-
11	SISP Retirement/Death Benefit Payments	(67,046)	(22,251)	(15,462)		(22,251)
12	FPCCSP Death Benefit Payments	91,500	30,367	21,102		30,367
13	Deferred Power Costs	(1,648,709)				-
14	Deferred Gas Costs		(332,079)	(230,767)		(332,079)
15	Non-qualified Retirement Plan Costs (Payments)					-
16	Travel & Entertainment Expense Disallowance	64,000	21,240	14,760		21,240
17	Contribution in Aid of Construction	58,358	19,367	13,459		19,367
18	Preferred Stock Dividend Paid Deduction	(29,952)	(9,940)	(6,908)		(9,940)
19	Net Tax Deduction (income) From Safe Harbor Lease					-
20	Amortization of Syn Financing Costs					-
21	Capital Trust Dividend Income					-
22	Non-taxable Insurance Proceeds	(234,852)	(77,942)	(54,163)		(77,942)
23	Additional ESOP Contributions	(501,876)	(166,560)	(115,745)		(166,560)
24	ESOP Dividends Paid Deduction	(913,620)	(303,208)	(210,704)		(303,208)
25	Long-term Disability Benefit Payments	(48,707)	(16,165)	(11,233)		(16,165)
26	Total	(1,382,577)	(223,972)	(278,977)	0	(223,972)
27	Federal Taxable Income	10,634,833	62,047	24,354	0	62,047

Northwestern Public Service Company
Income Taxes Recorded and as Adjusted
December 31, 1998 Test Year

Line No.		As Recorded					SD Gas Adjustments	SD Gas As Adjusted
			Gas					
		Electric	South Dakota	Nebraska	Other	Total		
1	Federal Income Tax Before Adjustments	$3,722,192	$21,716	$8,524	$4,053,249	$7,805,681		$21,716
2	Adjustments							
3	Deferred Tax Credit					0		
4	Normalizing Timing Difference (See Detail following)	577,048	116,228	80,768	0	774,044	0	774,044
5	True-up Adjustment to 1997 Tax Return	(1,901,838)	(631,173)	(438,611)	(1)	(2,971,623)		(2,971,623)
6	Federal Income Tax Adjustment	293,566	97,421	67,699		458,686		
7	ESOP Tax Entry	501,876	166,560	115,745		784,181		
9	Safe Harbor Lease Deferred Tax Benefit				1,680,115	1,680,115		
10	Non-Qual Retirement Plan Costs				27,232	27,232		
11	Miscellaneous				(200,287)	(200,287)		
12	Total	(529,348)	(250,964)	(174,399)	1,507,059	552,349	0	(2,197,579)
13	Federal Income Taxes - Current	3,192,844	(229,248)	(165,875)	5,560,308	8,358,029	0	(2,175,862)
14	Normalization of Current Timing Differences							
16	Deferred Power Costs	577,048				577,048		577,048
17	Deferred Gas Costs		116,228	80,768		196,996		196,996
19	Total	577,048	116,228	80,768	0	774,044	0	774,044

Note: Allocations are made on the following basis:
(1) Direct
(2) "F" Basis, Net Plant in Service at December 31, 1998
(3) Four Factor

Northwestern Public Service Company
Adjustments - Statement K
December 31, 1998 Test Year

Line No.		Electric	Gas		Total
			South Dakota	Nebraska	
1	Allocation of True-Up Adjustment Components				
2	Deferred Income Taxes	1,923,163	638,250	443,529	3,004,942
3	Deferred ITC				0
4	Current Taxes From Previous Calculation	(1,931,478)	(613,685)	(426,459)	(2,971,622)
5	Rounding				0
6	Total	(8,315)	24,565	17,070	33,320

Northwestern Public Service Company
Adjustments - Statement K
December 31, 1998 Test Year

Line No.		Electric	Gas		Total
			South Dakota	Nebraska	
1	Adjustment Consists of				
2	Normalize ESOP Dividends Paid Deduction	501,876	166,560	115,745	784,181
3	True-Up Adjustment Applicable to 1997 Tax Return	(1,931,478)	(613,685)	(426,459)	(2,971,622)
4	Federal Tax Adjustment	293,566	97,421	67,699	458,686
5	Normalize Timing Differences	577,048	116,228	80,768	774,044
6	Rounding				0
7	Total	(558,988)	(233,476)	(162,246)	(954,711)

Northwestern Public Service Company
Adjustments - Statement K
December 31, 1998 Test Year

Breakdown of Current Tax Provision in True-Up Adjustment Between Neb-SD

Line No.		South Dakota	Nebraska	Total
1	Add (Deduct):			
2	Current Provision of Tax Dep Less Than (In Excess of) Book	($22,389.32)	($15,558.68)	($37,948)
3	Deferred Directors' Fees	(2,623)	(1,822)	(4,445)
4	DRIP Administrative Expense	6,452	4,483	10,935
5	N/Q Retirement Plan Payment Costs, Net	353	246	599
6	Meals & Entertainment Disallowance	609	423	1,032
7	Long-Term Disability Benefit Liability	467	324	791
8	Overaccrual of Property Taxes	(11,465)	(7,968)	(19,433)
9	Overaccrual of Pension Expense	9,107	6,329	15,436
10	Underaccrual of Partnership Income	(4,113)	(2,859)	(6,972)
11	Bad Debts	(14,455)	(10,045)	(24,500)
12	General Reserves	(445,983)	(309,920)	(755,903)
13	Penalties	1,129	784	1,913
14	Lobbying Expense Disallowance	96	67	163
15	Deferred Interest	822	571	1,393
16	Tax Revenue Greater (Less) Than Book	(302,321)	(210,088)	(512,409)
17	Retirement/Death Benefits Paid Out (FPCCSP & SISP)	145	100	245
18	Amortization of Loss on Reacquired Debt	7,124	4,951	12,075
19	Environmental Clean-Up	26,669	18,533	45,202
20	Non-Taxable Insurance Proceeds	3,704	2,574	6,278
21	Long-Term Disability Benefit Payments	(607)	(421)	(1,028)
22	Capital Trust Dividend Income	5,903	4,102	10,005
23	Phantom Stock	30,225	21,003	51,228
24	Loss on Retirement of Fixed Assets	14,122	9,813	23,935
25	ADR Dismantling Costs	(36,174)	(25,138)	(61,312)
26	Vacation Pay	5,467	3,799	9,266
27	Adjustment for Graduated Rates	(18,146)	(12,610)	(30,756)
28	AMT	130,645	90,787	221,432
29	Low-Income Housing Credit	1,554	1,080	2,634
		(613,685)	(426,459)	(1,040,144)

Northwestern Public Service Company
Income Taxes - Gas - South Dakota
As Recorded and as Adjusted
December 31, 1998 Test Year

Line No.		Debit	Credit	Provision (Amortization) During Test Year	Adjustments	As Adjusted
1	Provision for Deferred Income Taxes	$1,421,419		$1,421,419		$1,421,419
2	Provision for Deferred Income Taxes-Credit		58,764	(58,764)		($58,764)
3	Net Provision for Deferred Income Taxes	$1,421,419	$58,764	$1,362,655	$0	$1,362,655
4	Investment Tax Credit Adjustment, Net		$28,320	($28,320)		($28,320)

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1994
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Net Income Per Books	$12,411,832	$3,028,375	$15,440,207	
2	Federal Income Taxes	6,295,474	1,573,869	7,869,343	
3	Income Subject to Tax Not Recorded on Books This Year:				
4	Tax Dividends Greater Than Book		12,573	12,573	
5	Safe Harbor Lease Income	2,923,082		2,923,082	
6	Contribution in Aid of Construction	163,325		163,325	
7	Dividends		66,956	66,956	
8	Emission Allowance	22,275		22,275	3,188,211
9	Expenses Recorded on Books This Year Not Deduction In This Return:				
10	DRIP Administration Expense	64,935		64,935	
11	Safe Harbor Lease Amortization	322,468		322,468	
12	Insurance Premiums	594,004		594,004	
13	Deferred Director Fees	56,030		56,030	
14	Deferred Power Costs	250,728		250,728	
15	Accrued Vacation Pay	9,157	59,826	68,983	
16	Penalties	3,002		3,002	
17	Long-Term Disability Liability	165,188		165,188	
18	Amortization of Loss on Reacquired Debt	140,569		140,569	
19	Death Benefit Liability	72,817		72,817	
20	Overaccrued State Income Taxes	82,244		82,244	
21	Deferred Gas Costs	1,091,903		1,091,903	
22	Lobbying Expense	62,845		62,845	
23	Deferred Interest Costs	10,560		10,560	
24	Meals and Entertainment Disallowance	64,702	62,833	127,535	
25	Spousal Travel Disallowance	10,000		10,000	
26	Prov in Excess of Charges - Bad Debts		27,466	27,466	
27	UNICAP Adjustment		3,433	3,433	3,154,710
28	Total	$6,109,834	$233,087	$6,342,921	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1994
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Income Recorded on Books This Year Not Included in This Return:				
2	Tax-Exempt Interest	$102,663	$65,269	$167,932	
3	Insurance Proceeds	47,331.00		47,331	
4	Amortization of Gain From Asset Retirement	925,644.00		925,644	
5	Tax Revenue Less Book	70,841.00		70,841	$1,211,748
6	Deductions in This Return Not Charged Against Book Income This Year:				
7	Depreciation	2,409,978.00		2,409,978	
8	Tax Less Than Book Partnership Income	20.00		20	
9	Accrued State Income Taxes	381,582.00	50,000.00	431,582	
10	ESOP Dividends Paid	1,004,969.00		1,004,969	
11	Additional ESOP Contribution	541,136.00		541,136	
12	Death Benefit Payments	81,060.00		81,060	
13	Retirement Benefit Payments	399,648.00		399,648	
14	ADR Dismantling Costs	106,810.00		106,810	
15	Pension Expense	837,903.00		837,903	
16	Environmental Tax	25,710.00		25,710	
17	Loss on Fixed Asset Retirements	830,772.00		830,772	
18	CNG Expense	150,874.00		150,874	
19	Environmental Clean-Up Expense	865,274.00		865,274	
20	General Reserve Charges	788,511.00	423,650.00	1,212,161	
21	General Reserve - Other	110,902.00		110,902	
22	Nonqualified Deferred Comp Payments	24,047.00		24,047	
23	Nonqualified Retirement Plan Payments	8,090.00		8,090	
24	Prepaid Insurance Costs		74,725.00	74,725	
25	FSC Commission		207,314.00	207,314	
26	Warranty Charges Greater Than Provision		24,637.00	24,637	
27	Advertising Expense		83,592.00	83,592	
28	Inventory Adjustment		61,821.00	61,821	9,493,025
29	Total	9,713,765.00	991,008.00	10,704,773.00	
30	Taxable Income	$15,103,375	$3,844,323	$18,947,698	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1995
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Net Income Per Books	$18,108,694	$1,160,890	$19,269,584	
2	Federal Income Taxes	8,249,902	526,590	8,776,492	
3	Income Subject to Tax Not Recorded on Books This Year:				
4	Safe Harbor Lease Income	3,353,806		3,353,806	
5	Contribution in Aid of Construction	130,898		130,898	
6	Dividends		16,294	16,294	
7	Emission Allowance	11,085		11,085	
8	Minority Interest		21,304	21,304	
9	NGC Management Fee	1,240,000		1,240,000	4,773,387
10	Expenses Recorded on Books This Year Not Deduction In This Return:				
11	Depreciation	17,815		17,815	
12	Travel & Entertainment	79,102	73,008	152,110	
13	Over Accrued Property Taxes	582,650		582,650	
14	DRIP Administration Expense	68,410		68,410	
15	Safe Harbor Lease Amortization	289,636		289,636	
16	Insurance Premiums	647,792	108,910	756,702	
17	Deferred Director Fees	11,121		11,121	
18	Deferred Power Costs	87,709		87,709	
19	Accrued Vacation Pay	6,511		6,511	
20	Penalties	718		718	
21	Long-Term Disability Liability			0	
22	Amortization of Loss on Reacquired Debt	112,600		112,600	
23	Nonqualified Deferred Compensation Plan	45,517		45,517	
24	Death Benefit Liability	519,637		519,637	
25	Nonqualified Retirement Plan Benefits			0	
26	Overaccrued State Income Taxes			0	
27	Deferred Gas Costs	103,823		103,823	
28	Lobbying Expense	60,901		60,901	
29	Deferred Interest Costs	10,560		10,560	
30	Spousal Travel Disallowance	10,000		10,000	
31	Prov in Excess of Charges - Bad Debts		50,663	50,663	
32	UNICAP Adjustment		7,872	7,872	
33	Inventory Adjustment		145,288	145,288	
34	NRT Warranty Charge		54,886	54,886	
35	Amortization		8,167	8,167	3,103,296
36	Total	$7,390,291	$486,392	$7,876,683	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1995
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Income Recorded on Books This Year Not Included in This Return:				
2	Tax-Exempt Interest	$179,225	$105,250	$284,475	
3	Tax Revenue Less Than Book	746,757		746,757	
4	Tax Dividends Less Than Book		87,793	87,793	
5	Insurance Proceeds	337,764		337,764	
6	Tax Less Than Book Partnership Income		6,603	6,603	
7	Amortization of ESP Sale Gain	501,390		501,390	
8	Book Gain on Sale in Excess of Tax		262,702	262,702	
9	Management Fee Inocme		1,240,000	1,240,000	
10	Equity in Subsidiaries	2,405,892	551,472	2,957,364	
11	Miscellansous Inc Rec on Bks Not Inc Ret - Other		13,310	13,310	$6,438,158
12	Deductions in This Return Not Charged Against Book Income This Year:				
13	Depreciation	1,906,574		1,906,574	
14	Tax Less Than Book Partnership Income	45,843		45,843	
15	Accrued State Income Taxes	382,792	52,847	435,639	
16	ESOP Dividends Paid	1,077,040		1,077,040	
17	Additional ESOP Contribution	579,943		579,943	
18	Long-Term Disability Payments	93,819		93,819	
19	Death Benefit Payments	74,935		74,935	
20	Retirement Benefit Payments	403,872		403,872	
21	ADR Dismantling Costs	51,959		51,959	
22	Pension Expense	987,566		987,566	
23	Environmental Tax	26,875		26,875	
24	Loss on Fixed Asset Retirements	439,270		439,270	
25	Under Accrued State Income Taxes	74,981		74,981	
26	Accrued Vacation Pay		90,183	90,183	
27	Environmental Clean-Up Expense	3,741,361		3,741,361	
28	General Reserve Charges	239,724	55,936	295,660	
29	Nonqualified Retirement Plan Payments	463		463	
30	Convention Prepaid		16,170	16,170	
31	Goodwill W/O		26,402	26,402	
32	FSC Commission		65,624	65,624	10,434,179
33	Total	14,298,045	2,574,292	16,872,337	
34	Taxable Income	$19,450,842	($400,420)	$19,050,422	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1998
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Net Income Per Books	$32,252,837	$3,876,166	$36,129,003	
2	Federal Income Taxes	9,190,451	4,410,170	13,609,621	
3	Income Subject to Tax Not Recorded on Books This Year:				
4	Tax Revenue Greater Than Book	4,968,601	309,056	5,277,657	
5	Safe Harbor Lease Income	3,847,832		3,847,832	
6	Contribution in Aid of Construction	123,915		123,915	
7	Tax Exceeds Book Partnership Income	14,203		14,203	
8	NGC Management Fee	3,162,500		3,162,500	
9	Gain on Redemption of Syn Inc. Preferred Stock	10,634,158		10,634,158	
10	Interest Income SYN, Inc.		43,228	43,228	
11	Deferred Tank Rent		1,425,210	1,425,210	
12	Gain on Redemption of CGI Holdings PS		232,917	232,917	
13	CGI Partnership Income Tax Greater Than Book		850	850	
14	Miscellaneous Adjustments		(856,194)	(856,194)	23,906,276
15	Expenses Recorded on Books This Year Not Deduction In This Return:				
16	Depreciation	603,527		603,527	
17	Travel & Entertainment	92,740	97,327	190,067	
18	General Reserve Charge	6,270,837		6,270,837	
19	Over Accrued Property Taxes	399,229		399,229	
20	DRIP Administration Expense	76,907		76,907	
21	Safe Harbor Lease Amortization	243,683		243,683	
22	Insurance Premiums	1,290,867		1,290,867	
23	Deferred Director Fees	56,424		56,424	
24	Penalties		35,136	35,136	
25	Long-Term Disability Liability	170,852		170,852	
26	Amortization of Loss on Reacquired Debt	98,569		98,569	
27	Death Benefit Liability	47,993		47,993	
28	Nonqualified Retirement Plan Benefits	3,571		3,571	
29	Overaccrued State Income Taxes		112,575	112,575	
30	Lobbying Expense	66,611		66,611	
31	Deferred Interest Costs	10,579		10,579	
32	Spousal Travel Disallowance	10,000	2,000	12,000	
33	Bad Debt Expense	300,000	623,640	923,640	
34	Increase in Pension Liability	326,540		326,540	
35	Inventory Adjustment		251,078	251,078	
36	Miscellaneous Adjustment		140,006	140,006	
37	Officers Bonus		94,586	94,586	
38	Fixed Asset Retirements		99,457	99,457	
39	Goodwill		243,289	243,289	
40	Contributions		4,035	4,035	
41	Miscellaneous Exp Rec on Bks Not Ded Ret - Other		12,685	12,685	
42	Amortization		41,494	41,494	11,826,237
43	Total	32,820,138	2,912,375	35,732,513	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1998
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Income Recorded on Books This Year Not Included in This Return:				
2	Tax-Exempt Interest	$88,819	$102,315	$191,134	
3	Tax Dividends Less Than Book	7,663,483	495,562	8,159,045	
4	Insurance Proceeds	31,195		31,195	
5	Equity in Subsidiaries	6,790,209	1,121,878	7,912,087	
6	Tax Revenue Less Book		394,256	394,256	
7	Tax Less Than Book Partnership Income		16,241,865	16,241,865	
8	Book Gain on Sale in Excess of Tax		370,471	370,471	
9	Management Fee Income		3,162,500	3,162,500	$36,462,553
10	Deductions in This Return Not Charged Against Book Income This Year:				
11	Depreciation	8,259,646		8,259,646	
12	Accrued State Income Taxes	434,863	277,313	712,176	
13	ESOP Dividends Paid	1,076,982		1,076,982	
14	Additional ESOP Contribution	579,912		579,912	
15	Death Benefit Payments	132,720		132,720	
16	Retirement Benefit Payments	403,872		403,872	
17	ADR Dismantling Costs	286,004		286,004	
18	Deferred Gas Costs	4,080,580		4,080,580	
19	Loss on Fixed Asset Retirements	57,926		57,926	
20	Accrued Vacation Pay	15,775	27,767	43,542	
21	Environmental Clean-Up Expense	260,661		260,661	
22	Nonqualified Deferred Comp Payments	143,410		143,410	
23	Acquisition Costs	6,360	1,628,798	1,635,158	
24	Deferred Power Costs	518,188		518,188	
25	Prepaid Insurance Costs		16,938	16,938	
26	FSC Commission		221,387	221,387	
27	Warranty Charges Greater Than Provision		10,067	10,067	
28	General Reserve Charges		25,414	25,414	
29	Other		43,684	43,684	
30	Inventory Adjustment		320,000	320,000	
31	Convention Prepaid		55,683	55,683	
32	Goodwill W/O		2,454	2,454	
33	UNICAP Adjustment		12,970	12,970	
34	Insurance Premiums		663,000	663,000	
35	Credit Balance A/R		182,557	182,557	
36	Franchise Taxes		14,063	14,063	
37	Sec 179(A) Clean Fuel Vehicles		125,000	125,000	
38	Legal A/R Bad Debt Allowance		4,821,098	4,821,098	
39	Bank Fees		87,259	87,259	24,792,351
40	Total	$30,830,605	$30,424,299	$61,254,904	
41	Taxable Income	$43,441,821	($19,225,588)	$24,216,233	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1997
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Net Income Per Books	$31,336,816	$11,702,636	$43,039,152	
2	Federal Income Taxes	7,733,637	3,230,150	10,963,787	
3	Income Subject to Tax Not Recorded on Books This Year:				
4	Interest Income Previously Taxed	828		828	
5	Safe Harbor Lease Income	4,112,234		4,112,234	
6	Contribution in Aid of Construction	128,231		128,231	
7	Gain on Disposition of Property	195,391		195,391	
8	Gain on Redemption CGI Holdings PS		47,822	47,822	
9	Tax Less Than Book Partnership Income		5,818,021	5,818,021	
10	Tax Revenue Greater Than Book		3,719,917	3,719,917	14,022,444
11	Expenses Recorded on Books This Year Not Deduction In This Return:				
12	Depreciation	763,003		763,003	
13	Travel & Entertainment	98,423	39,321	137,744	
14	DRIP Administration Expense	89,263		89,263	
15	Safe Harbor Lease Amortization	191,154		191,154	
16	Insurance Premiums	1,158,543		1,158,543	
17	Deferred Director Fees			0	
18	Deferred Power Costs	623,278		623,278	
19	Accrued Vacation Pay	75,643		75,643	
20	Penalties	44,589	8,509	53,098	
21	Long-Term Disability Liability	6,461		6,461	
22	Amortization of Loss on Reacquired Debt	98,569		98,569	
23	Nonqualified Deferred Compensation Plan	418,189		418,189	
24	Death Benefit Liability	708,583		708,583	
25	Nonqualified Retirement Plan Benefits	4,996		4,996	
26	Overaccrued State Income Taxes			0	
27	Deferred Gas Costs	3,920,486	(3,613,979)	306,507	
28	Lobbying Expense	68,333		68,333	
29	Deferred Interest Costs	10,540		10,540	
30	Spousal Travel Disallowance	15,000		15,000	
31	Prov in Excess of Charges - Bad Debts			0	
32	UNICAP Adjustment		20,006	20,006	
33	Increase in Pension Liability	126,005		126,005	
34	Environmental Clean-Up Expenses	633,105		633,105	
35	Inventory Adjustment		293,202	293,202	
36	Amortization		15,822	15,822	
37	Miscellaneous Adjustment		(59,999)	(59,999)	
38	Miscellaneous Exp Rec on Bks Not Ded Ret - Other		(83,818)	(83,818)	
39	Over Accrued Property Taxes		8,204	8,204	5,681,431
40	Total	$13,490,647	$6,213,028	$19,703,675	

Northwestern Public Service Company
Working Papers for Federal Income Taxes
Reconciliation of Income Per Books With
Income Per Return for the Calendar Year 1997
December 31, 1998 Test Year

Line No.	Description	NWPS	Subsidiaries	Consolidated	
1	Income Recorded on Books This Year Not Included in This Return:				
2	Tax-Exempt Interest	$172,486	$455,115	$627,601	
3	Insurance Proceeds	591,600		591,600	
4	Tax Revenue Less Book	4,182,933		4,182,933	
5	Tax Less Than Book Partnership Income	56,916	14,575,479	14,632,395	
6	Equity in Subsidiaries	12,549,445	6,774,262	19,323,707	
7	Interest Income Previously Taxed		43,228	43,228	
8	Tax Dividends Less Than Book		557,810	557,810	
9	Book Gain on Sale in Excess of Tax		867,902	867,902	
10	Other		1,862,163	1,862,163	$42,689,339
11	Deductions in This Return Not Charged Against Book Income This Year:				
12	Depreciation	67,732		67,732	
13	Accrued State Income Taxes	(62,250)	411,893	349,643	
14	ESOP Dividends Paid	1,273,356		1,273,356	
15	Additional ESOP Contribution	685,651		685,651	
16	Long-Term Disability Payments	108,490		108,490	
17	Charges Greater Than Provision for Injuries & Damages			0	
18	Death Benefit Payments	162,330		162,330	
19	Retirement Benefit Payments	436,032		436,032	
20	Loss on Reacquired Debt			0	
21	ADR Dismantling Costs	500,510		500,510	
22	General Reserve Charges	6,170,635	(36,462)	6,134,173	
23	Acquisition Costs	36,948		36,948	
24	Legal A/R Bad Debt Allowance	200,000		200,000	
25	Deferred Director Fees	36,289		36,289	
26	Under Accrued Property Tax	158,640		158,640	
27	Accrued Vacation Pay		(15,169)	(15,169)	
28	Convention Prepaid		(133,669)	(133,669)	
29	Goodwill W/O		26,402	26,402	
30	Other		21,607	21,607	
31	UNICAP Adjustment		(1,073)	(1,073)	
32	Insurance Premiums		(8,361)	(8,361)	
33	Terminated Acquisition Costs		154,507	154,507	
34	Contract Termination Fees		7,817,834	7,817,834	
35	FSC Commission		77,510	77,510	
36	Warranty Charges Greater Than Provision		29,973	29,973	18,119,355
37	Total	$27,327,743	$33,480,951	$60,808,694	
38	Taxable Income	$25,233,357	($12,335,237)	$12,898,120	

Northwestern Public Service Company
Working Papers For Claiming Allowance For State
Income Taxes Paid Each State In The Current Or Previous
Year Covered By The Test Period Including The Effect
Of Liberalized Depreciation On Such Taxes Paid
December 31, 1998

Line No.	Description	Electric	Gas Nebraska
1	Federal Taxable Income Per Statement K	$23,880,084	$23,880,084
2	Add: ACRS to ADR Adjustment	(1,594,370)	
3	Applicable Adjustments	677,093	2,745,872
4	Total Adjustments	(917,277)	2,745,872
5	Adjusted Federal Taxable Income	22,962,807	26,625,956
6	Apportionment Factor	0.039517	0.068012
7	Taxable Income	907,421	1,810,885
8	Tax on First $50,000	3,585	2,375
9	10.5% and 7.8% Respectively on Excess over $50,000	90,029	184,893
10	State Income Tax Allowance Per Statement K, p.1	93,614	187,268
11	Effect of Liberalized Depreciation		
12	Adjusted Federal Taxable Income Per Above	22,962,807	26,625,956
13	Add: Tax Depreciation Over Book From Statement K, p.1	(636,308)	(146,749)
14	ProForma Adjusted Federal Taxable Income	22,326,499	26,479,208
15	Apportionment Factor	0.039517	0.068012
16	ProForma Taxable Income	882,276	1,800,904
17	Tax on First $50,000	3,585	2,375
18	10.5% and 7.8% Respectively on Excess over $50,000	87,389	183,845
19	ProForma State Income Tax Allowance	90,974	186,220

Northwestern Public Service Company
Working Papers Accumulated Deferred ITC
December 31, 1998 Test Year

Line No.	Month	Electric	Gas Total	59% South Dakota	41% Nebraska
1	December 1997	$8,144,828	$756,241	$446,182	$310,059
2	January 1998	8,102,028	752,241	443,822	308,419
3	February 1998	8,059,228	748,241	441,462	306,779
4	March 1998	8,016,428	744,241	439,102	305,139
5	April 1998	7,973,628	740,241	436,742	303,499
6	May 1998	7,930,828	736,241	434,382	301,859
7	June 1998	7,888,028	732,241	432,022	300,219
8	July 1998	7,845,228	728,241	429,662	298,579
9	August 1998	7,802,428	724,241	427,302	296,939
10	September 1998	7,759,628	720,241	424,942	295,299
11	October 1998	7,716,828	716,241	422,582	293,659
12	November 1998	7,674,028	712,241	420,222	292,019
13	December 1998	7,631,228	708,241	417,862	290,379
14	Total	$102,544,364	$9,519,133	$5,616,288	$3,902,845
15	13 Month Average	$7,888,028	$732,241	$432,022	$300,219

Note: Gas allocation based on Four Factor allocation

Schedule K-2

Northwestern Public Service Company
Differences In Book And Tax Depreciation
December 31, 1998 Test Year

Line No.	Description	1994	1995	1996	1997
1	Depreciation Per Tax Return-				
2	Computed on a Straight Line Basis	105,019	181,960	193,354	441,972
3	Depreciation Computed Under Guideline Class Life System	530,836	451,650	384,529	306,612
4	Depreciation Computed Under ADR System	2,131,620	1,794,441	1,546,166	1,256,515
5	Depreciation Computed Under ACR System	4,447,868	4,426,627	1,716,975	1,398,766
6	Depreciation Computed Under MACR System	7,860,343	8,342,020	9,272,811	10,463,932
7	Total Depreciation Per Tax Return	15,075,686	15,196,698	13,113,835	13,867,797
8	Depreciation Per Books-				
9	Charged to Depreciation Expense	12,127,061	12,691,908	13,111,588	13,785,281
10	Charged to Other Accounts-				
11	Transportation Equipment	450,759	475,869	492,624	508,137
12	Coal Train Equipment	129,540	129,540	113,150	31,200
13	Miscellaneous				250,000
14	Total Depreciation Per Books	12,707,360	13,297,317	13,717,362	14,574,618
14	Additional (Less) Tax Depreciation Due to Application of				
15	Liberalized Methods for Tax Purposes	2,368,326	1,899,381	(603,527)	(706,821)

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR CLAIMED ALLOWANCES FOR STATE INCOME TAXES
INCOME TAX PAID EACH STATE IN THE CURRENT OR PREVIOUS YEAR
COVERED BY TEST PERIOD INCLUDING THE EFFECT
OF LIBERALIZED DEPRECIATION ON SUCH TAXES PAID
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	None

NORTHWESTERN PUBLIC SERVICE COMPANY
WORKING PAPERS FOR CONSOLIDATED FEDERAL INCOME TAX
DECEMBER 31, 1998 TEST YEAR

Statement Re Information Required By Schedule K-3 and K-4

As indicated on Schdule K-1, 1 of 4 through 4 of 4, the Company files a consolidated Federal Income Tax return. A tax sharing agreement was executed among all members of the consolidated group whereby total tax liability or benefit has been allocatsd to each member on a separate return basis as permitted under the applicable consolidated return treasury regulations. Under this agreement, each member subsidiary remits to or receives from the parent company its allocated portion of consolidated tax liability or benefit.

Northwestern Public Service Company
Other Taxes Classified Under Heading of
Federal, State and Local With Appropriate
Subclassifications for the Test Period-Gas-South Dakota

Reference is made to Exhibit_ (TPH-1), Schedule No. 6

NORTHWESTERN PUBLIC SERVICE COMPANY
OVERALL COST OF SERVICE - PER BOOKS
DECEMBER 31, 1998 TEST YEAR

Reference is made to Exhibit_(TPH-1), Schedule No. 1

NORTHWESTERN PUBLIC SERVICE COMPANY
ALLOCATED COST OF SERVICE
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	Reference is made to Exhibit_(TPH-1) - Revenue Requirements Study and Exhibit_(TPH-2) - Class Cost of Service Study.

NORTHWESTERN PUBLIC SERVICE COMPANY
COMPARISON OF COST OF SERVICE
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	Reference is made to Exhibit_(TPH-1).

NORTHWESTERN PUBLIC SERVICE COMPANY
DERIVATION OF INCREASED RATES
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	Reference is made to Exhibit_(TPH-1).

NORTHWESTERN PUBLIC SERVICE COMPANY
FUEL COST ADJUSTMENT FACTOR
DECEMBER 31, 1998 TEST YEAR

Line No.	
1	The Purchased Gas Adjustment filed for the month of May 1999 is also filed confidentially as part of this rate case. NorthWestern is not filing for any changes in calculating the Purchased Gas Adjustment as it is currently being calculated. The filing of the May Purchased Gas Adjustment is to comply to the procedural rule in Chapter 20:10:13:100.

NORTHWESTERN PUBLIC SERVICE
DESCRIPTION OF UTILITY OPERATIONS
DECEMBER 31, 1998 TEST YEAR

DESCRIPTION OF UTILITY OPERATIONS:

NorthWestern Public Service, a division of NorthWestern, provides competitive, reliable electric and natural gas service and value-added services to customers throughout the Midwest. As of December 31, 1998, NorthWestern Public Service provided retail electricity to 108 communities in South Dakota with a combined population of approximately 98,403 people. With regard to Natural Gas Operations, NorthWestern Public Service serves 61 retail communities, including 4 communities in Nebraska and 57 in South Dakota.

Electric Property

The Company's electric properties consist of an interconnected and integrated system. The Company, Otter Tail, and MDU jointly own Big Stone, a 455,783 kilowatt ("kw") nameplate capacity lignite-fueled electric generating plant and related transmission facilities. Big Stone is operated by Otter Tail for the benefit of the owners. The Company owns 23.4% of the Big Stone Plant.

The Company is one of four power suppliers, which jointly own Coyote I, a 455,783 kw nameplate capacity lignite-fueled electric generating plant and related transmission facilities located near Beulah, North Dakota. The Company has a 10% interest in Coyote I, which is operated by Otter Tail for the benefit of the owners.

The Company is one of the 14 power suppliers, which jointly own Neal #4, a 639,999 kw nameplate capacity coal-fueled electric generating plant and related transmission facilities located near Sioux City, Iowa. MidAmerican Energy is principal owner of Neal #4 and is the operator of the unit. The Company has an 8.7% interest in Neal #4.

In addition to its interest in Big Stone, Coyote I, and Neal #4, the Company owns and operates 19 oil and gas-fired units for peaking and reserve capacity.

As of December 31, 1993, the aggregate nameplate capacity of all Company-owned electric generating units is 327,419 kw, with an aggregate net summer peaking capacity of 308,289 kw and a net winter peaking capacity of 331,945 kw. The Company's maximum peak hourly demand of 276,976 kw occurred on July 14, 1998.

The Company's interconnected transmission system consists of 321.8 miles operating at 115 kilovolts ("kv") and 902.3 miles operating at 69 kv and 34.5 kv. The Company also owns three segments of transmission line, which are not tied to its internal system, in connection with its joint ownership in the three large steam generating plants. These lines consist of 18.2 miles of 230 kv line from Big Stone, 25.4 miles of 345 kv line from Neal #4, and 23.1 miles of 345 kv line from Coyote I. In addition to these lines, the Company owns 1,776.1 miles of distribution lines serving customers in more than 100 communities and adjacent rural areas. The Company owns 40 transmission substations with a total related capacity of 1,130,417 kilovolt amperes ("kva"), three mobile substations with a total capacity of 7,500 kva and 80 distribution substations with a total related capacity of 389,199 kva.

NORTHWESTERN PUBLIC SERVICE
DESCRIPTION OF UTILITY OPERATIONS
DECEMBER 31, 1998 TEST YEAR

Gas Property

On December 31, 1998, the Company owned 1,214 miles of distribution mains and appurtenant facilities in South Dakota. The Company also owns propane-air facilities in Brookings, Huron, and Mitchell, South Dakota, having a total related capacity of 10,140 MMBTU per day, which are operated for standby and peak shaving purposes only.

On December 31, 1998, the Company owned 692 miles of distribution mains and appurtenant facilities in Nebraska. The Company also owns propane-air facilities at Kearney and North Platte, Nebraska, having a total related capacity of 9,380 MMBTU per day, which are operated for standby and peak shaving purposes only.

BREAKDOWN OF SALES BETWEEN JURISDICTIONAL:

All of the Company's South Dakota gas sales revenue during the test year is under the jurisdiction of the South Dakota Public Utilities Commission.

STATUS OF LATEST RATE PROCEEDING:

The Company's most recent gas rate proceeding (Docket NG94-008) was filed with the South Dakota Public Utilities Commission on May 25, 1994. Said rates became effective November 15, 1994.

NorthWestern
PUBLIC SERVICE

600 Market Street W
Huron, SD 57350-1500
Telephone 605-352-8411
Facsimile 605-353-7519
Internet www.northwestern.com

May 5, 1999

Mr. William Bullard Jr., Executive Director
South Dakota Public Utilities Commission
State Capitol Building
Pierre, South Dakota 57501

Dear Mr. Bullard:

Enclosed herein are three (3) copies of 153rd Revised Sheet No. 9a and 50th Revised Sheet No. 9b of Northwestern's Gas Tariff.

Sheet Nos. 9a and 9b reflect changes in the costs of purchased gas and ad valorem taxes paid to be effective May 2, 1999.

The effect of Sheet Nos 9a and 9b for a typical space heating customer using 150 therms per month would be an increase in the cost from $82.53 to $86.60, about 4 7/8%. Application of these new rates will begin with meter readings on and after May 2, 1999.

Should you have any questions regarding the above changes, please advise.

Sincerely,

Jeff J. Decker

Jeff J. Decker

JJD

Enclosures

CONFIDENTIAL

#1

NorthWestern Public Service
South Dakota Rate Case
Purchases from Affiliated Companies
December 31, 1998 Test Year

Line No.	Description / Month During Test Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	CAPACITY PURCHASED FROM	Acct. No. 804							
2	NORTHWESTERN ENERGY								
3	January, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
4	February, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
5	March, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
6	April, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
7	May, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
8	June, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
9	July, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
10	August, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
11	September, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
12	October, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
13	November, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
14	December, 1998	48,000	1.0000	1.0000	48,000	1.0000	1.0000	48,000	0
15									
16		576,000			576,000			576,000	0
17									
18	MANAGEMENT FEE FROM	Acct. No. 923							
19	NORTHWESTERN ENERGY								
20	January, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
21	February, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
22	March, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
23	April, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
24	May, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
25	June, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
26	July, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
27	August, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
28	September, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
29	October, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
30	November, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
31	December, 1998	75,600	0.3600	0.5900	16,057	0.3400	0.5500	14,137	(1,920)
32									
33		907,200			192,684			169,644	(23,040)

NorthWestern Public Service
South Dakota Rate Case
Purchases from Affiliated Companies
December 31, 1998 Test Year

Line No.	Description / Month During Test Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	MANAGEMENT FEE FROM	Acct. No. 932							
2	NORCOM ADVANCED TECHNOLOGIES								
3	January, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
4	February, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
5	March, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
6	April, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
7	May, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
8	June, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
9	July, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
10	August, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
11	September, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
12	October, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
13	November, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
14	December, 1998	51,093	0.3600	0.5900	10,852	0.3400	0.5500	9,554	(1,298)
15									
16		613,116			130,224			114,648	(15,576)
17									
18	MANAGEMENT FEE FROM	Acct. No. 908							
19	NORTHWESTERN SERVICES								
20	January, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
21	February, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
22	March, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
23	April, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
24	May, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
25	June, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
26	July, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
27	August, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
28	September, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
29	October, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
30	November, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
31	December, 1998	299,157	0.5846	0.4944	86,464	0.5854	0.4952	86,723	259
32									
33		3,589,884			1,037,568			1,040,676	3,108
34									
35	Total	5,686,200			1,936,476			1,900,968	(35,508)
36									
37	ADJUST NORTHWESTERN								
38	SERVICES MANAGEMENT FEE	(1,089,884)	0.0000	0.0000	0	0.5854	0.4952	(315,947)	(315,947)
39									
40	TOTALS	4,596,316			1,936,476			1,585,021	(351,455)

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NG99-002
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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STATE OF SOUTH DAKOTA

BEFORE THE

PUBLIC UTILITIES COMMISSION

In the matter of:)
NORTHWESTERN PUBLIC SERVICE)
a division of NorthWestern Corporation, Applicant) Docket No. NG99-___

Application of NorthWestern Public Service a division of NorthWestern Corporation

For Increased Natural Gas Rates

December 31, 1998 Test Year

Testimony & Exhibits

NorthWestern Public Service

Original

NorthWestern
PUBLIC SERVICE

NorthWestern Public Service
Docket No. NG99-____
Prepared Testimony Summary

Michael J. Hanson:

Describes NorthWestern's rate filing and the reasons why NorthWestern is proposing to increase its natural gas distribution rates. Explains what communities and industries NorthWestern has brought natural gas to since its last rate filing. States that due primarily to these expansions, test year weather adjusted therm throughput is 30% higher than therms used to design rates in the last rate proceeding.

David A. Monaghan:

Sets forth information concerning the accounting procedures of the Company. David is the Chief Accounting Officer, and therefore has responsibility for all accounting records of NorthWestern Corporation, including its utility division NorthWestern Public Service.

Rodney F. Leyendecker:

Sponsors the Company's capital structure, including the calculation of deriving the weighted average cost of capital to apply to the Company's rate base. Sponsors the requested 11.25% rate of return on common equity. In addition, he sets forth certain information relating to the determination of the South Dakota Gas Revenue Requirement.

Jeffrey J. Decker:

Provides information on the weather adjustment made to actual test year throughput. Test year heating degree-days were approximately 85% of normal. As a result, actual throughput during the test period has been adjusted upwards to derive test year adjusted billing and allocation units.

Thomas P. Hitchcock:

Sets forth information to determine the South Dakota Gas Revenue Requirement. In addition he sponsors a class cost of service study for gas utility operations within the South Dakota jurisdiction. He also supports NorthWestern's rate design and proposed rate tariff changes.

SOUTH DAKOTA FACT SHEET

Description	Last Rate Case	Current Rate Case
Date of Filing	05/25/94	06/01/99
Date Rates Became Effective	11/15/94	00/00/00
Test Year - 12 Months Ended	12/31/93	12/31/98
Requested Return on Equity %	11.75%	11.25%
Requested Overall Return %	9.33%	9.27%
Common Equity % of Overall Capital Structure	46.43%	49.65%
Allowed Return on Equity %	11.25%	Unknown
Allowed Overall Return %	9.09%	Unknown
Requested Increase in Revenues - $	$2,417,703	$2,108,112
Requested Increase in Revenues - %	7.10%	6.26%
Allowed Increase in Revenues - $	$2,124,313	Unknown
Allowed Increase in Revenues - %	6.20%	Unknown
Requested Increase in Residential Revenues - %	12.90%	6.37%
Allowed Increase in Residential Revenues - %	11.33%	Unknown
Total Gas Customers		38,670
Total Residential Customers		33,404
Average Residential Consumption in Therms - Year		994
Average Residential Monthly Bill - Before Increase		$50.37
Average Residential Monthly Bill - After Increase		$53.57

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	**Docket No. NG99-_____**
NORTHWESTERN PUBLIC SERVICE,	)	
a division of NorthWestern Corporation	)	

DIRECT TESTIMONY
OF
MICHAEL J. HANSON

Q. Please state your name and business address for the record.

A. Michael J. Hanson, 600 Market Street West, Huron, South Dakota 57350.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Public Service ("NorthWestern" or "Company") as President and Chief Executive Officer.

Q. Please describe your education and business experience.

A. I have been the President and Chief Executive Officer for the Company since May of 1998. I was employed seventeen years with Northern States Power in a variety of positions before coming to NorthWestern. I was General Manager and Chief Executive Officer of NSP – South Dakota from 1994-1998. I attended the United States Naval Academy from 1977-79 and graduated from the University of Wisconsin in 1982 with a Bachelor of Science in accountancy. I received a Juris Doctor degree from William Mitchell College of Law in 1989. Exhibit ___ (MJH-1) contains a listing of my education and business experience.

Q. What is the purpose of your prepared direct testimony?

A. In my prepared direct testimony, I will describe NorthWestern's rate filing and the reasons why NorthWestern is proposing to increase its natural gas distribution rates at this time.

Q. Please describe the organization and operation of NorthWestern.

A. NorthWestern is an electric and gas distribution utility. NorthWestern serves 137 South Dakota communities with approximately 38,670 gas and 55,965 electric customers in its South Dakota service territory. It also provides natural gas service to approximately 39,486 customers in four communities in Nebraska.

Q. What is the purpose of this rate filing?

A. The purpose of this filing is twofold. The first purpose is to request an appropriate return on the Company's natural gas operations in South Dakota. NorthWestern last filed for a rate increase in 1994. Since that filing, NorthWestern has experienced increased costs in operating its gas utility. Additionally, NorthWestern has expanded its distribution system to bring natural gas to several communities, colonies and agricultural businesses in South Dakota. The second purpose is to add Mellette and Wolsey to NorthWestern's service territory map.

Q. Please describe the rate increase request?

A. NorthWestern proposes an increase in natural gas distribution rates of $2,108,112, or 6.26 percent. Details of the proposed rates and charges are shown in the filed revised tariff schedules as described in the direct testimony and exhibits of Thomas P. Hitchcock.

Q. Please describe NorthWestern's customer notification of the proposed increase.

A. On June 1, 1999, NorthWestern will post a notice of proposed increase in all of its

offices. On the same day, a release will be issued to the news media. At the conclusion of this case, a notice will be mailed to all South Dakota natural gas customers informing them of any rate changes granted by the Commission.

Q. Please explain what communities and industries NorthWestern has brought natural gas to since its last rate filing.

A. NorthWestern is committed to meeting the natural gas needs of business and non-business people in South Dakota. In its efforts to meet the ever expanding needs of the people of South Dakota, NorthWestern has made natural gas available to the communities of Wolsey, Hayti, Mellette and Revillo. We also added the colonies of Elm Springs, Claremont, Oaklane, Millbrook, Rockport, Rosedale, Hutterville, Mayfield, Clark, Fordham, Hillside, Hillcrest, Orland and Graceville. Finally, NorthWestern has expanded its gas distribution system to support South Dakota's agricultural economy. Major system expansions have been made to help make possible the soybean processing plant in Volga, the Ethanol plant in Huron and the South Dakota Wheat Growers expansions in Huron, Wolsey, Aberdeen and Mellette. NorthWestern will continue to work with all customers to add growth and value to their operations. This growth has helped to offset the loss of its largest volume customer with the closing of Dakota Pork Industries in Huron in 1997. Dakota Pork had accounted for 5% of the natural gas volume.

Q. What affect have these expansions had on NorthWestern's South Dakota system deliveries since its last rate filing?

A. Total therms used to design rates in NorthWestern's last rate case were 75 million. Test year weather adjusted throughput in this filing is over 99 million therms, a 30 percent

increase.

Q. In addition to the expansion of its distribution system, what other developments have taken place at NorthWestern to add value to the service provided by NorthWestern to its customers?

A. In 1995 a new operations center was completed in Huron. This building allowed NorthWestern to consolidate core departments in one building, instead of having the various departments located in several different buildings in Huron. Furthermore, a call center was established to improve customer service and understand customer expectations. A more efficient natural gas meter testing and repair facility was added. Although the construction of this facility was a significant undertaking, it has been and will continue to be an important part of NorthWestern's efforts to meet customer needs and maintain reliability of its natural gas distribution system in an ever-changing society.

Q. What is NorthWestern doing to improve customer service and increase system efficiency and reliability?

A. NorthWestern is constantly searching for ways to improve service to both its customers and team members. NorthWestern is implementing a program to enhance the work environment of its team members. An enhanced work environment will lead to innovations and efficiencies that will improve all aspects of customer service. Furthermore, NorthWestern continuously surveys its customers to determine what can be done to enhance the value of our services. Finally, NorthWestern is constantly reviewing its processes and procedures. This constant evolution will enable NorthWestern to anticipate and meet changes in the utility industry. These are ongoing efforts that will be

reviewed continually and enhanced with modern technology.

Q. Does that conclude your prepared direct testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

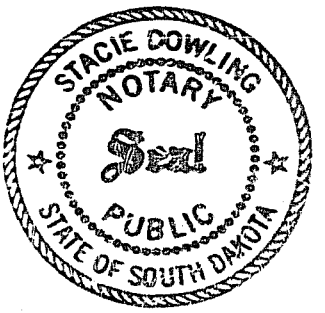
I, Michael J. Hanson, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Michael J. Hanson

Subscribed and sworn to before me this 26th day of May, 1999.

Stacie Dowling 9/24/04
Notary Public in and for the State of South Dakota



Biographical Data For

Exhibit___(MJH-1)

MICHAEL J. HANSON
47258 272nd Street
Sioux Falls, South Dakota 57108

Position:	President & CEO NorthWestern Public Service, Huron, South Dakota
Date Effective:	June 1, 1998
Job History:	1981-82 Northern States Power - Gas Operating Clerk 1981-83 Northern States Power - Accounting Coordinator 1983-84 Northern States Power - Accountant 1984-89 Northern States Power - Internal Auditor 1989-94 Northern States Power - Attorney 1994-98 Northern States Power - General Manager & Chief Executive 1998-Present NorthWestern Public Service - President & CEO
Birth:	December 12, 1958 Sparta, Wisconsin
Military Service:	Navy, 1977-1979 Midshipman Second Class (W-4)
Education:	Sparta Senior High School, 1977 United States Naval Academy, 1977-79 University of Wisconsin, 1982, BS William Mitchell College of Law, 1989, Juris Doctor
Family:	Married Laura K. Eggers, Sparta, Wisconsin, February 16, 1980 Children - Justin M. Hanson - born May 25, 1982 Danielle M. Hanson - born March 19, 1985
Directorships:	Sioux Council Boy Scouts Board (President) Marquette Bank - Sioux Falls Sioux Falls Development Foundation (Chairman) (1997-98) Fargo Cass County Economic Development Corp (1997-98) Sioux Vocational Services (1994-97) Sioux Empire United Way (1994-97)

Club and Association Memberships:

Edison Electric Institute
South Dakota Electric Utility Companies (Chairman)
Minnesota State Bar Association
Hennepin County Bar Association
American Bar Association
Institute of Internal Auditors
South Dakota Rural Enterprises, Inc.
North East Council of Governments
Downtown Rotary Club, Sioux Falls
Gloria Dei Lutheran Church

Recognitions:	Juris Doctor Magna Cum Laude (1989) James R. Kelly Award (CIA Exam) (1984) Certificate of Excellence – Certified Internal Auditor Exam (1984) Daughters of the American Revolution Good Citizenship Award (1977) Student Council President (1976-77) Class President (1974-75)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	**Docket No. NG99-_____**
NORTHWESTERN PUBLIC SERVICE,	)	
a division of NorthWestern Corporation	)	

DIRECT TESTIMONY
OF
DAVID A. MONAGHAN

Q. Please state your name and business address for the record.

A. David A. Monaghan. My business address is NorthWestern Corporation, 125 S. Dakota Avenue, Suite 1100, Sioux Falls, South Dakota 57104.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Corporation as Controller and Treasurer.

Q. Please describe your education and business experience.

A. I graduated from Southwest Missouri State University in 1989 with a Bachelor of Science degree in Accounting and received a Masters of Accountancy degree from the Southwest Missouri State University in 1990. After graduating in 1990, I became a staff auditor with Baird, Kurtz & Dobson Co. ("BK&D") an independent public accounting firm. While with BK&D, I was promoted several times and left the firm while in the position of manager. In 1996, I joined NorthWestern Public Service Company (the predecessor name of NorthWestern Corporation) as Controller. I was promoted to Controller and Treasurer in 1997. I have served in that capacity from 1997 until the present time.

Q. **What is the purpose of your testimony?**

A. The purpose of my prepared direct testimony is to set forth information concerning the accounting procedures of NorthWestern Corporation and its NorthWestern Public Service division.

Q. **On what basis are the accounting records of NorthWestern maintained?**

A. The accounting records of NorthWestern are maintained on the accrual basis in accordance with generally accepted accounting principles. They are also maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) for public utilities subject to the provisions of the Federal Power Act and Natural Gas Act.

Q. **Are the accounting procedures, controls, records and financial reporting techniques of NorthWestern subject to periodic review and close scrutiny from sources independent of those responsible for their preparations?**

A. Yes. In addition to the review of accounting procedures and transactions on the part of myself and the accounting staff of NorthWestern, NorthWestern accounting and reporting procedures and documentation are subject to periodic independent review by various organizations including:

1) Arthur Andersen LLP ("Andersen"), a firm of independent public accountants, performs a quarterly review of NorthWestern's books and records. Andersen also performs an annual audit of the books and records as part of the process of certifying NorthWestern's annual financial statements.

2) The FERC performs periodic audits of NorthWestern's accounting and financial

records.

3) The Internal Revenue Service (IRS) performs an audit of all federal income tax returns that are filed by NorthWestern Corporation. The IRS reviews many aspects of NorthWestern's accounting and financial records in connection with these audits. State tax authorities, such as the South Dakota Department of Revenue, conduct audits of NorthWestern's accounting and financial records as well.

4) The South Dakota Public Utilities Commission may audit facets of NorthWestern's books and records, including various cost of service expenditures, energy cost adjustment factors, PGA factors and refunds. In Nebraska the municipalities served by NorthWestern, which regulate the charges for natural gas, may audit aspects of NorthWestern's books and records.

5) NorthWestern's Internal Audit Department performs audits of various accounting systems and records, including a comprehensive review of the system of internal accounting controls and procedures. In addition, the Audit Committee of NorthWestern's Board of Directors regularly reviews the financial reporting and confers both Andersen and the Internal Audit Department concerning NorthWestern's systems, controls and procedures.

6) There are other governmental agencies, such as the United States Securities and Exchange Commission, that also conduct periodic audits and review various aspects of NorthWestern's books and records.

Q. What is contained in Exhibit__ (DAM-1)?

A. Exhibit __ (DAM-1) is the affidavit signed by me as chief accounting officer of NorthWestern which states that the cost statements, working papers, and other supporting data submitted as part of this filing or maintained by NorthWestern in support of the filing accurately set forth the books of NorthWestern, pursuant to Administrative Rule 20:10:13:50. Many of these statements are also supported by the testimony of NorthWestern witnesses Leyendecker and Hitchcock.

Q. What is contained in Exhibit__ (DAM-2)?

A. A. Exhibit__ (DAM-2) is a report showing the allocations and direct billings of NorthWestern Corporation common costs to its various subsidiary and affiliate companies. Allocation of the NorthWestern Corporation common costs between NorthWestern's electric and natural gas businesses, and further allocation of the natural gas business common costs between South Dakota and Nebraska operations is provided by the testimony of NorthWestern witness Hitchcock.

Q. Does Exhibit __ (DAM-2) constitute a change from NorthWestern's 1994 rate filing and previous rate filings in South Dakota?

A. Yes. In 1998, NorthWestern reorganized its operations, accompanying its name change from Northwestern Public Service Company to NorthWestern Corporation. The utility portion of the business became an unincorporated division of the parent company, and the various non-utility business segments are being conducted in wholly-owned subsidiary companies and majority-owned affiliate entities. All of these entities were formed in 1994 or later. Some examples of the wholly-owned subsidiaries are:

(a) NorthWestern Energy Corporation engages in the non-regulated energy sales

and marketing business, with end-user customers in South Dakota.

(b) NorthWestern Services Corporation delivers services and solutions to residential and business customer for their energy use systems and for a variety of other customer needs in seven states, including South Dakota.

(c) NorCom Advanced Technologies, Inc. provides communications, data and networking solutions for small commercial businesses in South Dakota, North Dakota and Nebraska.

(d) NorthWestern Growth Corporation researches and implements investment and acquisition strategies for NorthWestern Corporation, including NorthWestern's investments in affiliate companies CornerStone Propane, L.P., Blue Dot Services Inc. and Expanets, Inc.

Exhibit __ (DAM-2) provides a summary of the various cost items that are allocated or directly billed to these entities.

Q. Is NorthWestern pursuing any additional strategies that will affect the allocations used in arriving at the South Dakota operating income statement?

A. Yes, NorthWestern continues to refine its allocations and direct billings related to its business relationships among these various entities. To the extent possible, we will charge corporate costs to our business operations in place of allocations, and where allocations need to be used, to make these as reasonable as possible. Each time an organizational change is made, a whole new series of questions presents itself causing further focus and discussion of how costs flow. The guiding principle in all of these discussions is to increase direct assignment of costs and reduce allocations where

possible.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

I, David A. Monaghan, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

David A. Monaghan

Subscribed and sworn to before me this 27th day of May, 1999.

Stacie Dowling 9/24/04
Notary Public in and for the State of South Dakota

STACIE DOWLING NOTARY Seal PUBLIC STATE OF SOUTH DAKOTA

Exhibit ___ (DAM-1)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN RE:)
NORTHWESTERN PUBLIC SERVICE,) **Docket No. NG99-_____**
a division of NorthWestern Corporation)

AFFIDAVIT OF DAVID A. MONAGHAN

STATE OF SOUTH DAKOTA)
COUNTY OF MINNEHAHA) **SS**

David A. Monaghan, being first duly sworn, deposes and says:

(1) He is the Controller and Treasurer of NorthWestern Corporation ("NorthWestern"), and in such capacity serves as its Chief Accounting Officer;

(2) As such Chief Accounting Officer, he has responsibility for all accounting records of NorthWestern, including its utility division NorthWestern Public Service;

(3) He has reviewed all cost statements, working papers, and other supporting data submitted as part of this filing or maintained by NorthWestern and NorthWestern Public Service, and such cost statements, working papers, and other supporting data accurately set forth the books of NorthWestern and NorthWestern Public Service.

David A. Monaghan

Subscribed and sworn to this 27th day of May, 1999.

Notary Public, South Dakota
My Commission Expires: 3/6/2001

(Notary Seal)

Exhibit ___ (DAM-2)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN RE:)
NORTHWESTERN PUBLIC SERVICE,) Docket No. NG99-_____
a division of NorthWestern Corporation)

NORTHWESTERN CORPORATION
ALLOCATIONS AND DIRECT BILLINGS
AMONG CORPORATE ENTITIES

Common Cost Allocations:

Cost of Capital
Insurance
Subsidiary Management Services

Direct Billings from NorthWestern Public Service to subsidiaries and affiliates:

Advertising Expense
Telephone Expense
Computer Equipment and Support
Service Technicians
Call Center Services
Janitorial Services

Direct Billings from subsidiaries and affiliates to NorthWestern Public Service (refer to Statement R):

Communications Equipment and Support
Energy Management Services
Pipeline Capacity Charges
Community Relations and Office Management Services
Service Technicians

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	Docket No. NG99-____
NORTHWESTERN PUBLIC SERVICE	)	
a division of NorthWestern Corporation	)	

DIRECT TESTIMONY
OF
RODNEY F. LEYENDECKER

Q. Would you please state your name and business address for the record.

A. Rodney F. Leyendecker. My business address is 33 Third St. S.E., Huron, South Dakota.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Energy Corporation as President and CEO.

Q. Please describe your education and business experience.

A. I graduated from Bemidji State University in 1968 with a Bachelor of Arts Degree with an accounting major and an economics minor. I am a member of the American Institute of Certified Public Accountants, the District of Columbia Institute of Certified Public Accountants and the South Dakota Society of Certified Public Accountants, Inc. In January, 1969, I began employment as an auditor within the Office of Accounting and Finance of the Federal Power Commission headquartered jn Washington, D.C. I remained with the Commission until joining NorthWestern Public Service in January, 1975.

Q. Have you testified previously?

A. Yes, I have testified on accounting and ratemaking related matters in several proceedings before this Commission, as well as the Federal Energy Regulatory Commission and state and federal courts.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring exhibits that show the calculation of:

(1) the Company's capital structure as of December 31, 1998, the close of the test year; and

(2) the weighted average cost of capital to apply to the Company's rate base.

As a part of deriving the overall cost of capital, I am sponsoring the Company's requested rate of return on common equity that is fair maintains the firm's financial integrity, and allows NorthWestern to attract capital on reasonable terms. In addition, my testimony sets forth certain information relating to the determination of the South Dakota Gas Revenue Requirement for NorthWestern Public Service ("NorthWestern", "Company" or "NPS").

Q. Were your exhibits prepared by you or under your supervision?

A. Yes, they were.

Q. What is the frequency with which NorthWestern has filed for rate relief for natural gas service?

A. Since the Commission assumed jurisdiction over electric and gas utility service in July 1975, the Company has filed for and received rate relief for gas service on four occasions. These increases became effective February 1, 1981, April 1, 1982, November 15, 1986, and November 15, 1994, respectively. This represents the fifth request by NorthWestern

for a general increase applicable to natural gas operations in South Dakota since the Commission assumed jurisdiction over these matters in 1975. So its been averaging about five years between filings. By the time rates approved in this proceeding become effective, nearly five years will have lapsed since implementation of the last general increases to our South Dakota natural gas customers.

Q. **What level of revenue increase is NorthWestern requesting in this filing from its South Dakota Gas System?**

A. NorthWestern is seeking an overall increase in operating revenues of $2,108,000, or 6.26 percent. This calculation is shown on Exhibit _____(RFL-1).

Q. **Would you outline the parameters which been have utilized in presenting the Company's overall cost of service in this application?**

A. Yes. Section 20:10:13:44 of the Commission's filing rules prescribe guidelines within which adjustments to actual test period data may be claimed. Specifically, adjustments much be

> "based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within twenty-four months of the last month of the test period."

The adjustments proposed herein represents the Company's best estimates, within the confines of Section 20:10:13:44, in an attempt to provide for a matching of revenues

and expenses during the period resulting rates will be effective. Additionally, the instant filing reflects the principles which were employed in the settlement of previous dockets before this Commission.

Q. Mr. Leyendecker, would you briefly describe some of the major adjustments included in the Company's proposed overall cost of service in this application?

A. Yes. As I stated earlier, in preparing this case, NorthWestern has adhered to the principles utilized in earlier settlements. The principle cost of service adjustments included in this application relate to weather normalization, new customer gas load, rate case, advertising, and labor expenses, changes in cost due to updated common allocation factors, affiliate management fees and interest synchronization. All of the adjustments are explained in detail by witnesses Hitchcock, Decker and Monaghan.

Q. Have you reviewed the pro forma adjustments included in NorthWestern's filing, and do you have an opinion on them?

A. Yes. I have reviewed all the pro forma adjustments. In my opinion they follow sound ratemaking principles, and are consistent with adjustments reflected in the settlement in prior NorthWestern dockets.

Q. Have you prepared an exhibit containing the Company's proposed capital structure and its weighted average cost of capital?

A. Yes, Exhibit ___ (RFL-2) contains information that develop the required overall cost of capital. The Company is proposing to use the consolidated capital structure, and related cost of capital, of NorthWestern Corporation.

Q. Please describe your calculation of the long-term debt component, and the related

cost to apply to the long-term debt component.

A. This component was determined by summing the outstanding balance of each issue of long-term debt at December 31, 1998. I calculated the annual test year interest cost for each outstanding long term debt issue by multiplying the principal amount of each debt issue by the stated coupon rate of the issue and summing these products. In the case of miscellaneous seller notes, which include many small debt issues, I have included the actual average coupon rates on this debt during the base period. The interest expense is then combined with the base year actual amortization of debt discount and issuance expense, to arrive at the annual cost of long term debt. By dividing the annual long-term debt expenses by the long-term debt balance I determined a cost of long term debt of 7.3006%.

Q. **Please describe your calculation of the preferred stock and securities component, and the related cost to apply to the preferred stock and securities component.**

A. This component was determined by summing the outstanding balance of each issue of preferred stock and securities at December 31, 1998. I calculated the annual test year dividend cost for each outstanding preferred stock or security issue by multiplying the principal amount of each issue by the stated dividend rate of the issue and summing these products. By dividing the annual preferred stock and securities expenses by the preferred stock and securities balance I determined a cost of preferred stock and securities of 7.4437%.

Q. **Please describe your calculation of the common equity component.**

A. This component was determined by calculating the balance as of December 31, 1998 for

the appropriate common equity accounts.

Q. What is the Company requesting as return on common equity?

A. NorthWestern has included the cost of common equity in the cost of service presented herein at 11.25%. This represents the same level granted by the Commission in settlement of NorthWestern's last South Dakota proceeding in 1994 and is near the average range of authorized levels granted other gas companies during the last six years.

Q. Have you prepared an exhibit that shows how returns to natural gas companies has trended in the past?

A. Yes, I have. This information is shown on Exhibit ___ (RFL-3).

Q. Please continue with your testimony as to the requested return on common equity.

A. Return on equity is not a significant cost component in the cost of service of a typical natural gas distributor such as NorthWestern. For example, as filed herein, the entire common equity cost component represents only 6.3 percent of the total cost of service. Yet, it is the determining factor as to whether a distributor files for rate relief. As such, the ability of a distributor to secure and achieve reasonable returns on equity directly affects the frequency of rate filings.

During the years prior to the Commission's assumption of regulatory authority, when NorthWestern was regulated by the Cities in which it provided service, rate increases were implemented in a manner so as to produce a return at the high end of what might be deemed a reasonable range, thus, providing adequate return during the earlier period that rates were in effect. Achieved return would then be allowed to drift to the low end of that range or below before an additional increase was sought. In doing so, the

Company was able to avoid a high frequency of rate activity.

I believe that principle to be even more important today, because now we must not only deal with the unpleasantness of imposing an increase on customers, we must also consider the higher cost of achieving rate relief. This is, of course, a cost which will find its way right back to the natural gas ratepayer. I believe that NorthWestern's South Dakota gas customers have been fortunate not to have been made to bear significant costs of this nature in the past.

I am hopeful that such costs can be held to a minimum in the future. I do not believe that our gas customer's interests are best served if NorthWestern were to seek rate relief on an annual basis. This is particularly a danger with respect to NorthWestern's gas operations, in view of the narrow range, in terms of dollars, between what the Commission may deem as an adequate rate of return and that which the Company may find to be unacceptable rate of return. This, of course, is due to the relatively low investment level, or rate base, of a gas distributor when viewed in terms of the total cost of service.

Q. How did you determine the overall cost of capital to apply to the Company's rate base?

A. The calculation of the weighted average cost of capital is also shown on Exhibit __ (RFL-2). This exhibit shows each of the balances for each of the components of the Company's capital structure. The proportion that each component represents of the total capitalization is then calculated. These proportions are then multiplied times the component costs to arrive at the weighted average cost. As indicated on the exhibit, the

weighted average cost of capital is 9.2714%.

Q. Has the Company filed a class cost of service study as part of this filing?

A. Yes, Mr. Hitchcock was assigned the responsibility for preparation of the study. He will sponsor testimony relating to assignment of class cost responsibility and the resulting rate design proposed to recover required revenue levels.

Q. Does this conclude your prepared direct testimony in this proceeding?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

I, Rodney F. Leyendecker, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Rodney F. Leyendecker

Subscribed and sworn to before me this 25th day of May, 1999.

Stacie Dowling 9/26/04
Notary Public in and for the State of South Dakota



NorthWestern Public Service
Docket No. NG99-_____
South Dakota Gas Revenue Requirement
Test Year Ended December 31, 1998

Exhibit___(RFL-1)

Line No.	Description	South Dakota Gas	Reference
	(a)	(b)	(b)
1	Rate Base	$36,974,359	Exhibit __(TPH-1), Sch. 9, Col. (g), Line 28
2			
3	Rate of Return	9.2714%	Exhibit __(TPH-1), Sch. 9.2, Col. (h), Line 7
4			
5	Required Return	$3,428,041	Line 1 multiplied by Line 3
6			
7	Adjusted Test Year Operating Income	$2,054,586	Exhibit __(TPH-1), Sch. 1, Col. (e), Line 19
8			
9	Change in Operating Income	$1,373,455	Line 5 minus Line 7
10			
11	Income Tax Effect -		
12	Federal @ 35%	$739,553	Line 9 divided by .65 times .35
13			
14	Revenue (Excess) Deficiency	$2,113,008	Line 9 plus Line 12
15	Gross Receipts Tax @ 0.0015	$3,162	Exhibit __(TPH-1), Sch. 1, Col. (f), Line 13
16	MGP Removal Cost Adjustment	($8,058)	Exhibit __(TPH-1), Sch. 1, Col. (f), Line 10
17			
18	Total Revenue (Excess) Deficiency	$2,108,112	Line 14 plus Line 15 plus Line 16
19			
20			
21	Test Year Pro Forma Revenue	$33,657,074	Exhibit __(TPH-1), Sch. 1, Col. (e), Line 6
22			
23	Revenue Requirement	$35,765,186	Line 18 plus Line 21
24			
25	Revenue Requirement % Change	6.26%	Line 18 divided by Line 21

NorthWestern Public Service
Consolidated Cost of Capital - NorthWestern Corporation
December 31, 1997 and 1998

Schedule No. 9.2
Page 1 of 1

Line No.	Description	Reference	Beginning of Period Capital Amounts	End of Period Amounts			Annual Interest or Dividend	Weighted Cost of Capital
				Capital Amounts	Ratios	Cost of Capital		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$	%	%	$	%
1	Long-Term Debt	Line 27	425,281,000	588,875,000	43.5904%	7.3006%		3.1824%
2								
3	Preferred Stock Equity & Securities	Line 35	36,250,000	91,250,000	6.7546%	7.4437%		0.5028%
4								
5	Common Stock Equity		366,318,000	670,803,000	49.6550%	11.2500%		5.5862%
6								
7	Total Capitalization		827,849,000	1,350,928,000	100.0000%			9.2714%
8								
9								
10	Long-Term Debt Detail							
11	First Mortgage Bonds							
12	7.000% Series			55,000,000		7.0000%	3,850,000	
13	6.990% Series			15,000,000		6.9900%	1,048,500	
14	6.950% Series			105,000,000		6.9500%	7,297,500	
15	7.100% Series			60,000,000		7.1000%	4,260,000	
16	Pollution Control Obligations							
17	5.900% Series			6,400,000		5.9000%	377,600	
18	5.900% Series			4,000,000		5.9000%	236,000	
19	5.850% Series			7,550,000		5.8500%	441,675	
20	5.900% Series			3,400,000		5.9000%	200,600	
21	Senior Secured Debt							
22	7.530% Series			220,000,000		7.5300%	16,566,000	
23	7.330% Series			85,000,000		7.3300%	6,230,500	
24	Other Long-Term Debt							
25	Miscellaneous Seller Notes			27,525,000		8.1500%	2,243,288	
26	Amort. of Debt Disc. and Expense	Acct. 428					239,513	
27								
28	Total Long-Term Debt			588,875,000		7.3006%	42,991,176	
29								
30	Preferred Stock and Securities Detail							
31	4.500% Series			2,600,000		4.5000%	117,000	
32	8.125% Series			32,500,000		8.1250%	2,640,625	
33	7.200% Series			55,000,000		7.2000%	3,960,000	
34	6.500% Series			1,150,000		6.5000%	74,750	
35								
36	Total Preferred Stock and Securities			91,250,000		7.4437%	6,792,375	

Exhibit___(RFL-2)

apparent that Virginia Power's unrestricted right to the income did not exist. Therefore, the Court held that there was a substantive nexus between the income event and the repayment event.

Further, the IRS argued that the refunds did not qualify as deductible business expenses. The IRS asserted that the refunds constituted a reduction in income as held in the decisions of Roanoke Gas Co. v. United States, 977 F. 2d 131 (1992); Southwestern Energy Co. v. Commissioner, 100 T.C. 500 (1993) and Iowa Southern Utilities Co. v. United States, 11 Cl. Ct. 868 (1987), aff'd 841 F.2d 1108 (Federal Cir. 1988). Again the Court disagreed with the IRS' view. The Court found that the cases cited above involved materially different factual circumstances. Unlike the cases cited above, Virginia Power was required to make a refund, rather than change the price charged for future services. The obligation to make refunds was legally binding and enforceable, and Virginia Power was actually out-of-pocket for the payments it made. As a result, because the refunds were both "ordinary and necessary" and incurred during the taxable year in carrying on Virginia Power's business, they qualified as deductible business expenses under IRC Section 162(a).

Accordingly, the court determined that Virginia Power met the requirements of IRC Section 1341 and was entitled to a reduction of its 1991 tax liability.

Environmental Clean-Up Costs

In the second issue decided by the Court, Virginia Power transferred property on which an electric generation plant was located to another subsidiary of Dominion Resources, Inc. It was the intention of the other subsidiary to develop the property and cease generation of electricity on this property. Upon discovery of contaminants from the property, Dominion Resources, Inc. contended that the clean-up costs were incidental repairs that are deductible under IRC Section 162. The Court held that the environmental clean-up costs are not currently deductible and must be capitalized under IRC Section 263 based on the "put versus keep" distinction. That is, the expenses were incurred to "put" the property into a useable condition for a new and different use as a real estate development business, rather than to "keep" the property in its previous condition as an electric power plant.

For more information or questions on this case, please call **Jeff Balch** at (619) 231-4571 or by e-mail at jbalch@dttus.com.

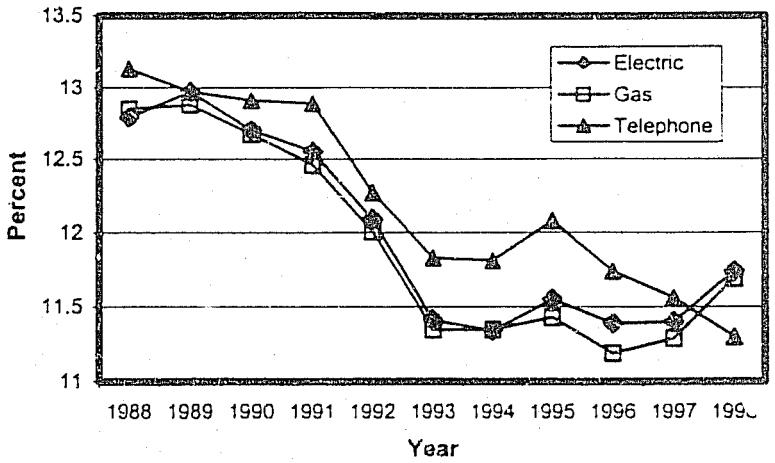
REGULATORY RATE STUDY

In a study published by Regulatory Research Associates, Inc. (RRA) entitled *Major Rate Case Decisions -- January 1997 – December 1998, Supplemental Study*, RRA has presented key data from all major rate for the years 1997 and 1998 by type of utility service and included summary information from cases decided in the last eleven years.

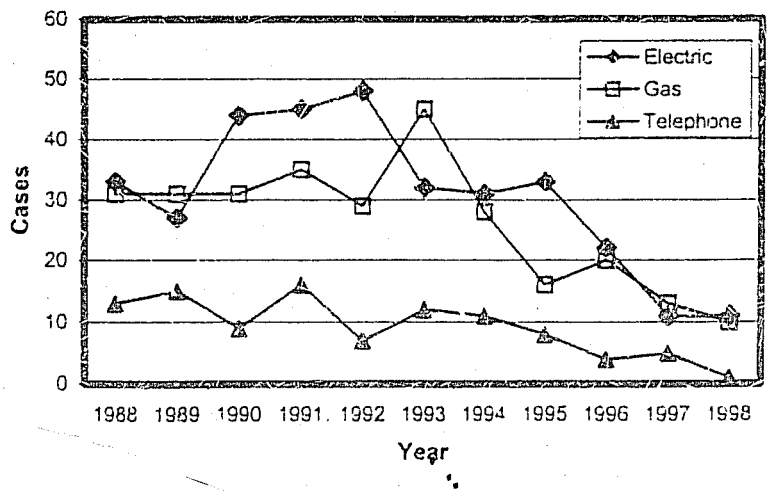
The regulatory study data indicates that the average equity return authorized electric utilities in 1998 approximated 11.7% which is a modest increase from the authorized 11.4% in 1997. There were 11 electric determinations in both 1997 and 1998, significantly fewer than the 33 cases determined in 1988. Based on 13 gas cases in 1997, and 10 gas cases in 1998, the average return

on equity authorized for gas utilities increased slightly from approximately 11.3% in 1997 to approximately 11.5% in 1998. There was only one equity return determination, 11.3%, in the telecommunications industry in 1998, compared to five determinations in 1997, with an average return on equity of approximately 11.6%.

Average Authorized Return on Equity



Number of Equity Return Determinations



As depicted above, RRA's study indicates a downward trend in the number of equity return determinations in current years. Reasons for this trend include: industry restructuring/intensifying competition; more efficient utility operations; technological improvements; relatively low interest and inflation rates; accelerated depreciation and amortization programs; and the growing use of performance or price-based regulation.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:)
) Docket No. NG99-____
NORTHWESTERN PUBLIC SERVICE)
a division of NorthWestern Corporation)

DIRECT TESTIMONY OF JEFFREY J. DECKER

Q. Please state your name and business address for the record.

A. Jeffrey J. Decker, 33 Third St. S.E., Huron. South Dakota 57350.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Energy Corporation as Manager Pricing – Services.

Q. Please describe your education and business experience and business credentials.

A. I graduated in 1986 from Dakota Wesleyan University with a Bachelor of Arts degree in Business Administration.

I joined NorthWestern Public Service in 1988 as a corporate accountant working with fniancial reporting. Starting in 1993 I worked with NorthWestern Growth Corporation. My responsibilities included financial analysis of potential companies to be aquired. In 1995 I became the director of rates. I was promoted to Manager of Financial Services – NEC in 1998. Since 1996 I have been responsible for developing the NorthWestern Public Service Gas revenue budgets for South Dakota and Nebraska. I also maintain and analyze heating degree day data for both states on a monthly basis.

Q. What is the purpose of your prepared direct testimony?

A. I am supporting the weather normalization pro forma adjustment to the income statement sponsored by Company witness Hitchcock. The heating degree days by cycle are shown in Exhibit (JJD-2). The revenue adjustments are calculated on Exhibit (JJD-1) Pages 1 through 12.

Weather Normalization

Q. Please explain Exhibit (JJD-2), Page 1 of 1.

A. The 1998 test year was warmer than normal, which resulted in lower sales and revenues. I have adjusted the test year revenues to correspond to normal weather.

Q. What affect did weather normalization have on South Dakota Revenues?

A. The total net weather adjustment reflects an increase to the Company's test year net income as a result of weather normalizing billed sales and unbilled sales for twelve months ending December 31, 1998. The calculation to obtain this adjustment is included in Exhibit (JJD-1) Pages 1-12. Volumes were adjusted by class. Adjusted volumes were then used to calculate revenues at present and proposed rates.

Q. Please explain the methodology used to calculate the weather normalization adjustment.

A. The methodology used for the normalization is consistent with that used in determining the annual forecasted sales for the calculation of the NorthWestern budget projections. This method calculates a normalization factor by taking the sum of the monthly heating degree day normals and dividing them by the sum of the monthly degree day actuals. Heating degree days for actual and normal are calculated on a billing cycle basis to

provide a better match with revenues. This normalization factor is applied to actual annual sales (less baseload sales) to either decrease actual sales if it is colder than normal or increase sales if it is warmer than normal.

Q. Please state the source for the normal and actual heating degree day information.

A. The normal and actual degree days are reported by the National Oceanic and Atmospheric Administration. The monthly Normal Heating Degree Days are based on a thirty year average for the period of 1961-1990.

In calculating consistently with the NorthWestern gas revenue budget methodology, I used the Huron weather service actual and normal heating degree data. Huron is located close to the center of our service territory and represents a reasonable average of the weather affecting our customers.

Q. Have you prepared any analysis which indicates the use of Huron only weather data is reasonable in your weather adjustment?

A. Yes, I have. This is contained on Exhibit ___ (JJD-3).

Q. What does this exhibit demonstrate?

A. Shown on this exhibit is the heating degree data for calendar year 1998 for Huron, Aberdeen and Sioux Falls, South Dakota. NorthWestern's gas markets fall in or near these locations. The data shows that Huron experienced more warmer than normal weather then either Aberdeen or Sioux Falls during 1998.

Q. Had you used the average data for these three cities in your weather adjustment, what would have been the result?

A. Since the average heating degree day variance is less than Huron, the results from a

weather adjustment using the average data would have produced a lower weather adjustment. This would have resulted in a need for a larger revenue increase.

Q. Does this conclude your prepared direct testimony in this proceeding?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

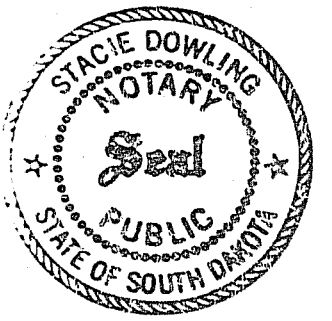
I, Jeffrey J. Decker, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Jeffrey J. Decker
Jeffrey J. Decker

Subscribed and sworn to before me this 25th day of May, 1999.

Stacie Dowling 9/26/04
Notary Public in and for the State of South Dakota



NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Residential - Rate Code 81

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			First 30	Over 30		
2			Therms	Therms		
3						
4	August 1998 Therm Units		445,110	42,450	0	487,560
5	September 1998 Therm Units		431,820	41,180	0	473,000
6						
7	Subtotal		876,930	83,630	0	960,560
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		5,261,580	501,780	0	5,763,360
11	Total Therm Units - Base Year		8,756,400	20,094,330	0	28,850,730
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,494,820	19,592,550	0	23,087,370
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,152,850	23,281,580	0	27,434,430
19	Add: Baseload Therms Above		5,261,580	501,780	0	5,763,360
20						
21	Total Therm Units - Test Year		9,414,430	23,783,360	0	33,197,790

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	400,847	$4 50	$1,803,812	400,847	$4.50	$1,803,812	$6 00	$2,405,082
29	Distribution Delivery Commodity Charge								
30	First 30 therms	8,758,400	$0.2138	$1,870,117	9,414,430	$0.2000	$1,882,886	$0 2474	$2,329,469
31	Over 30 therms	20,094,330	$0.1350	$2,711,761	23,783,360	$0.1220	$2,901,570	$0.1320	$3,139,404
32	Ad Valorem Tax Adjustment	7,749,420	$0.0150	$116,407	33,197,790	$0.0156	$517,886	$0.0156	$517,886
33	MGP Removal Cost Adjustment	28,850,730	$0.0140	$403,910	33,197,790	$0.0140	$464,769	$0.0140	$464,769
34	Gas Cost Commodity Charge	28,850,730	$0.2419	$6,980,315	33,197,790	$0.2043	$6,782,308	$0.2043	$6,782,308
35	Gas Cost Demand Charge	28,850,730	$0.1463	$4,220,687	33,197,790	$0.1758	$5,836,171	$0.1758	$5,836,171
36									
37	Totals	28,850,730		$18,107,009	33,197,790		$20,189,402		$21,475,089
38	Less: Gas Cost			$11,201,002			$12,618,479		$12,618,479
39									
40	Margin			$6,906,007			$7,570,923		$8,856,610

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Exhibit___(JJD-1)
Page 1 of 12

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Small Commercial - Rate Code 82

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			First 400	Next 1,600	Over 2,000	
2			Therms	Therms	Therms	
3						
4	August 1998 Therm Units		207,530	81,880	1,240	290,650
5	September 1998 Therm Units		193,870	48,470	1,160	243,500
6						
7	Subtotal		401,400	130,350	2,400	534,150
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		2,408,400	782,100	14,400	3,204,900
11	Total Therm Units - Base Year		7,526,830	5,234,330	1,070,870	13,832,030
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		5,118,430	4,452,230	1,056,470	10,627,130
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		6,082,170	5,290,530	1,255,390	12,628,090
19	Add: Baseload Therms Above		2,408,400	782,100	14,400	3,204,900
20						
21	Total Therm Units - Test Year		8,490,570	6,072,630	1,269,790	15,832,990
22						

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
23									
24									
25									
26									
27									
28	Customer Charge	58,889	$4.50	$265,001	58,889	$4.50	$265,001	$7.00	$412,223
29	Distribution Delivery Commodity Charge								
30	First 400 therms	7,526,830	$0.1249	$940,440	8,490,570	$0.1141	$968,774	$0.1471	$1,248,890
31	Next 1,600 therms	5,234,330	$0.0941	$492,621	6,072,630	$0.0841	$510,708	$0.0941	$571,434
32	Over 2,000 therms	1,070,870	$0.0634	$67,924	1,269,790	$0.0541	$68,696	$0.0591	$75,045
33	Ad Valorem Tax Adjustment	3,723,860	$0.0095	$35,413	15,832,990	$0.0099	$156,747	$0.0099	$156,747
34	MGP Removal Cost Adjustment	13,832,030	$0.0140	$193,648	15,832,990	$0.0140	$221,662	$0.0140	$221,662
35	Gas Cost Commodity Charge	13,832,030	$0.2419	$3,345,923	15,832,990	$0.2043	$3,234,680	$0.2043	$3,234,680
36	Gas Cost Demand Charge	13,832,030	$0.1462	$2,022,566	15,832,990	$0.1758	$2,783,440	$0.1758	$2,783,440
37									
38	Totals	13,832,030		$7,363,536	15,832,990		$8,209,708		$8,704,121
39	Less: Gas Cost			$5,368,489			$6,018,120		$6,018,120
40									
41	Margin			$1,995,047			$2,191,588		$2,686,001

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Exhibit___(JJD-1)
Page 2 of 12

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Firm - Rate Code 84 (Option A)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		112,810	0	0	112,810
5	September 1998 Therm Units		107,840	0	0	107,840
6						
7	Subtotal		220,650	0	0	220,650
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		1,323,900	0	0	1,323,900
11	Total Therm Units - Base Year		4,842,970	0	0	4,842,970
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,519,070	0	0	3,519,070
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,181,670	0	0	4,181,670
19	Add: Baseload Therms Above		1,323,900	0	0	1,323,900
20						
21	Total Therm Units - Test Year		5,505,570	0	0	5,505,570

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	1,963	$70.00	$137,410	1,963	$70.00	$137,410	$80.00	$157,040
29	Distribution Delivery Commodity Charge								
30	All therms	4,842,970	$0.0362	$175,327	5,505,570	$0.0364	$200,403	$0.0462	$254,199
31	Ad Valorem Tax Adjustment	1,234,890	$0.0061	$7,484	5,505,570	$0.0064	$35,236	$0.0064	$35,236
32	MGP Removal Cost Adjustment	4,842,970	$0.0140	$67,802	5,505,570	$0.0140	$77,078	$0.0140	$77,078
33	Gas Cost Commodity Charge	4,842,970	$0.2212	$1,071,243	5,505,570	$0.2300	$1,266,281	$0.2300	$1,266,281
34	Gas Cost Demand Charge	425,480	$0.8373	$356,265	425,480	$0.8700	$370,168	$0.8700	$370,168
35	Released Capacity/Balancing Surcharge	598,200	$0.0170	$10,170	680,040	$0.0170	$11,561	$0.0170	$11,561
36									
37	Totals	4,842,970		$1,825,701	5,505,570		$2,098,137		$2,171,563
38	Less: Gas Cost			$1,437,678			$1,648,010		$1,648,010
39									
40	Margin			$388,023			$450,127		$523,553

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Exhibit___(JJD-1)
Page 3 of 12

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Firm - Rate Code 84 (Option B)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		750	0	0	750
5	September 1998 Therm Units		1,620	0	0	1,620
6						
7	Subtotal		2,370	0	0	2,370
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		14,220	0	0	14,220
11	Total Therm Units - Base Year		364,500	0	0	364,500
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		350,280	0	0	350,280
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		416,230	0	0	416,230
19	Add: Baseload Therms Above		14,220	0	0	14,220
20						
21	Total Therm Units - Test Year		430,450	0	0	430,450

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
28	Customer Charge	24	$260.00	$6,240	24	$260.00	$6,240	$280.00	$6,720
29	Distribution Delivery Commodity Charge								
30	All therms	364,500	$0.0185	$6,742	430,450	$0.0180	$7,748	$0.0225	$9,685
31	Ad Valorem Tax Adjustment	78,990	$0.0042	$331	430,450	$0.0042	$1,808	$0.0042	$1,808
32	MGP Removal Cost Adjustment	364,500	$0.0140	$5,103	430,450	$0.0140	$6,026	$0.0140	$6,026
33	Gas Cost Commodity Charge	364,500	$0.2212	$80,626	430,450	$0.2300	$99,004	$0.2300	$99,004
34	Gas Cost Demand Charge	18,120	$0.8373	$15,172	18,120	$0.8700	$15,764	$0.8700	$15,764
35	Released Capacity/Balancing Charge	45,030	$0.0170	$766	53,180	$0.0170	$904	$0.0170	$904
36									
37	Totals	364,500		$114,980	430,450		$137,494		$139,911
38	Less: Gas Cost			$96,564			$115,672		$115,672
39									
40	Margin			$18,416			$21,822		$24,239

Exhibit___(JJD-1)
Page 4 of 12

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Interruptible - Rate Code 85 (Option A)

Schedule No. 2.1
Page 5 of 9

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		53,000	0	0	53,000
5	September 1998 Therm Units		54,700	0	0	54,700
6						
7	Subtotal		107,700	0	0	107,700
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		646,200	0	0	646,200
11	Total Therm Units - Base Year		3,416,180	0	0	3,416,180
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		2,769,980	0	0	2,769,980
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		3,291,530	0	0	3,291,530
19	Add: Baseload Therms Above		646,200	0	0	646,200
20						
21	Total Therm Units - Test Year		3,937,730	0	0	3,937,730
22						

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
23									
24									
25									
26									
27									
28	Customer Charge	1,404	$70.00	$98,280	1,329	$70.00	$93,030	$80.00	$106,320
29	Distribution Delivery Commodity Charge								
30	All therms	3,416,180	$0.0348	$118,879	3,937,730	$0.0364	$143,333	$0.0462	$181,810
31	Ad Valorem Tax Adjustment	1,987,000	$0.0063	$12,445	3,937,730	$0.0064	$25,201	$0.0064	$25,201
32	MGP Removal Cost Adjustment	3,416,180	$0.0140	$47,827	3,937,730	$0.0140	$55,128	$0.0140	$55,128
33	Gas Cost Commodity Charge	3,416,180	$0.2152	$735,223	3,937,730	$0.2300	$905,678	$0.2300	$905,678
34	Released Capacity/Balancing Charge	3,416,180	$0.0170	$58,076	3,416,180	$0.0170	$58,076	$0.0170	$58,076
35									
36	Totals	3,416,180		$1,070,730	3,937,730		$1,280,446		$1,332,213
37	Less: Gas Cost			$793,299			$963,754		$963,754
38									
39	Margin			$277,431			$316,692		$368,459

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Exhibit___(JJD-1)
Page 5 of 12

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Interruptible - Rate Code 85 (Option B)

Schedule No. 2.1
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Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		8,970	0	0	8,970
5	September 1998 Therm Units		9,910	0	0	9,910
6						
7	Subtotal		18,880	0	0	18,880
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		113,280	0	0	113,280
11	Total Therm Units - Base Year		428,430	0	0	428,430
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		315,150	0	0	315,150
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		374,490	0	0	374,490
19	Add: Baseload Therms Above		113,280	0	0	113,280
20						
21	Total Therm Units - Test Year		487,770	0	0	487,770
22						

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
23									
24									
25									
26									
27									
28	Customer Charge	48	$260.00	$12,480	48	$260.00	$12,480	$280.00	$13,440
29	Distribution Delivery Commodity Charge								
30	All therms	428,430	$0.0177	$7,580	487,770	$0.0180	$8,780	$0.0225	$10,975
31	Ad Valorem Tax Adjustment	216,510	$0.0041	$892	487,770	$0.0042	$2,049	$0.0042	$2,049
32	MGP Removal Cost Adjustment	428,430	$0.0140	$5,998	487,770	$0.0140	$6,829	$0.0140	$6,829
33	Gas Cost Commodity Charge	428,430	$0.2152	$92,206	487,770	$0.2300	$112,187	$0.2300	$112,187
34	Released Capacity/Balancing Charge	428,430	$0.0170	$7,283	487,770	$0.0170	$8,292	$0.0170	$8,292
35									
36	Totals	428,430		$126,439	487,770		$150,617		$153,772
37	Less: Gas Cost			$99,489			$120,479		$120,479
38									
39	Margin			$26,950			$30,138		$33,293

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Exhibit___(JJD-1)
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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Rate Code 87 (Option A)

Line No.	Description		Block 1	Block 2	Block 3	Total
	(a)		(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		28,080	0	0	28,080
5	September 1998 Therm Units		27,900	0	0	27,900
6						
7	Subtotal		55,980	0	0	55,980
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		335,880	0	0	335,880
11	Total Therm Units - Base Year		1,172,050	0	0	1,172,050
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		836,170	0	0	836,170
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		993,610	0	0	993,610
19	Add: Baseload Therms Above		335,880	0	0	335,880
20						
21	Total Therm Units - Test Year		1,329,490	0	0	1,329,490

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	237	$70.00	$16,590	312	$70.00	$21,840	$130.00	$40,560
29	Distribution Delivery Commodity Charge								
30	All therms	1,172,050	$0.0388	$45,430	1,329,490	$0.0364	$48,393	$0.0462	$61,384
31	Extended Service Rider Discount			$0			$0		$0
32	Ad Valorem Tax Adjustment	523,710	$0.0062	$3,262	1,329,490	$0.0064	$8,509	$0.0064	$8,509
33	MGP Removal Cost Adjustment	1,172,050	$0.0140	$16,409	1,329,490	$0.0140	$18,613	$0.0140	$18,613
34									
35	Totals	1,172,050		$81,691	1,329,490		$97,355		$129,066
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$81,691			$97,355		$129,066

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Exhibit___(JJD-1)
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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Rate Code 87 (Option B)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		1,363,020	0	0	1,363,020
5	September 1998 Therm Units		1,356,620	0	0	1,356,620
6						
7	Subtotal		2,719,640	0	0	2,719,640
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		16,317,840	0	0	16,317,840
11	Total Therm Units - Base Year		20,293,140	0	0	20,293,140
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,975,300	0	0	3,975,300
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,723,800	0	0	4,723,800
19	Pro Forma New Load		7,200,000	0	0	7,200,000
20	Add: Baseload Therms Above		16,317,840	0	0	16,317,840
21						
22	Total Therm Units - Test Year		28,241,640	0	0	28,241,640

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
23									
24									
25									
26									
27									
28									
29	Customer Charge	493	$260.00	$128,180	588	$260.00	$152,880	$330.00	$194,040
30	Distribution Delivery Commodity Charge								
31	All therms	20,293,140	$0.0196	$397,731	28,241,640	$0.0180	$508,350	$0.0225	$635,437
32	Extended Service Rider Discount			($39,446)			($42,090)		($47,322)
33	Ad Valorem Tax Adjustment	8,471,760	$0.0038	$32,032	28,241,640	$0.0042	$118,615	$0.0042	$118,615
34	MGP Removal Cost Adjustment	20,293,140	$0.0140	$284,104	28,241,640	$0.0140	$395,383	$0.0140	$395,383
35									
36	Totals	20,293,140		$802,601	28,241,640		$1,133,138		$1,296,153
37	Less: Gas Cost			$0			$0		$0
38									
39	Margin			$802,601			$1,133,138		$1,296,153

Exhibit___(JJD-1)
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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		667,270	0	0	667,270
5	September 1998 Therm Units		675,900	0	0	675,900
6						
7	Subtotal		1,343,170	0	0	1,343,170
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		8,059,020	0	0	8,059,020
11	Total Therm Units - Base Year		9,309,890	0	0	9,309,890
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		1,250,870	0	0	1,250,870
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		1,486,390	0	0	1,486,390
19	Pro Forma New Load		854,900	0	0	854,900
20	Add: Baseload Therms Above		8,059,020	0	0	8,059,020
21						
22	Total Therm Units - Test Year		10,400,310	0	0	10,400,310
23						

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
24									
25									
26									
27		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
28									
29	Customer Charge	36	$260.00	$9,360	36	$260.00	$9,360	$330.00	$11,880
30	Distribution Delivery Commodity Charge								
31	All therms	9,309,890	$0.0097	$90,659	10,400,310	$0.0069	$72,016	$0.0077	$80,074
32	Extended Service Rider Discount			($1,113)			($1,166)		($1,166)
33	Ad Valorem Tax Adjustment	3,741,910	$0.0037	$13,948	10,400,310	$0.0042	$43,682	$0.0042	$43,682
34	MGP Removal Cost Adjustment	9,309,890	$0.0075	$69,742	10,400,310	$0.0070	$72,962	$0.0062	$64,904
35									
36	Totals	9,309,890		$182,596	10,400,310		$196,854		$199,374
37	Less: Gas Cost			$0			$0		$0
38									
39	Margin			$182,596			$196,854		$199,374

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
South Dakota Soybean Processors - Volga

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		418,330	0	0	418,330
5	September 1998 Therm Units		327,140	0	0	327,140
6						
7	Subtotal		745,470	0	0	745,470
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		4,472,820	0	0	4,472,820
11	Total Therm Units - Base Year		5,291,040	0	0	5,291,040
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		818,220	0	0	818,220
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		972,280	0	0	972,280
19	Pro Forma New Load		854,900	0	0	854,900
20	Add: Baseload Therms Above		4,472,820	0	0	4,472,820
21						
22	Total Therm Units - Test Year		6,300,000	0	0	6,300,000

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
29	Customer Charge	12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
30	Distribution Delivery Commodity Charge								
31	All therms	5,291,040	$0.0056	$29,815	6,300,000	$0.0032	$19,908	$0.0037	$23,121
32	Extended Service Rider Discount			$0			$0		$0
33	Ad Valorem Tax Adjustment	2,205,550	$0.0038	$8,280	6,300,000	$0.0042	$26,460	$0.0042	$26,460
34	MGP Removal Cost Adjustment	5,291,040	$0.0048	$25,397	6,300,000	$0.0046	$29,232	$0.0041	$26,019
35									
36	Totals	5,291,040		$66,612	6,300,000		$78,720		$79,560
37	Less: Gas Cost			$0			$0		$0
38									
39	Margin			$66,612			$78,720		$79,560
40									
41	Total Commodity Rate =	$0.01200	per therm						

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
3M - Brookings

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		216,330	0	0	216,330
5	September 1998 Therm Units		312,020	0	0	312,020
6						
7	Subtotal		528,350	0	0	528,350
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		3,170,100	0	0	3,170,100
11	Total Therm Units - Base Year		3,462,260	0	0	3,462,260
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		292,160	0	0	292,160
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		347,170	0	0	347,170
19	Add: Baseload Therms Above		3,170,100	0	0	3,170,100
20						
21	Total Therm Units - Test Year		3,517,270	0	0	3,517,270

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
29	Distribution Delivery Commodity Charge								
30	All therms	3,462,260	$0.0154	$53,290	3,517,270	$0.0130	$45,619	$0.0142	$49,840
31	Extended Service Rider Discount			$0			$0		$0
32	Ad Valorem Tax Adjustment	1,325,790	$0.0037	$4,873	3,517,270	$0.0042	$14,773	$0.0042	$14,773
33	MGP Removal Cost Adjustment	3,462,260	$0.0112	$38,779	3,517,270	$0.0108	$38,092	$0.0096	$33,871
34									
35	Totals	3,462,260		$100,062	3,517,270		$101,604		$102,444
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$100,062			$101,604		$102,444
39									
40	Total Commodity Rate =	$0.02800	per therm						

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
Saputo Cheese - Big Stone

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		32,610	0	0	32,610
5	September 1998 Therm Units		36,740	0	0	36,740
6						
7	Subtotal		69,350	0	0	69,350
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		416,100	0	0	416,100
11	Total Therm Units - Base Year		556,590	0	0	556,590
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		140,490	0	0	140,490
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		166,940	0	0	166,940
19	Add: Baseload Therms Above		416,100	0	0	416,100
20						
21	Total Therm Units - Test Year		583,040	0	0	583,040

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
29	Distribution Delivery Commodity Charge								
30	All therms	556,590	$0.0136	$7,554	583,040	$0.0111	$6,489	$0.0122	$7,113
31	Extended Service Rider Discount			($1,113)			($1,166)		($1,166)
32	Ad Valorem Tax Adjustment	210,570	$0.0038	$795	583,040	$0.0042	$2,449	$0.0042	$2,449
33	MGP Removal Cost Adjustment	556,590	$0.0100	$5,566	583,040	$0.0097	$5,638	$0.0086	$5,014
34									
35	Totals	556,590		$15,922	583,040		$16,530		$17,370
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$15,922			$16,530		$17,370
39									
40	Total Commodity Rate =	$0.02500	per therm						

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Exhibit___(JJD-1)
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NorthWestern Public Service
Normalization of Billing Units - Heating Degree Days
Huron, South Dakota

Schedule No. 2.2
Page 1 of 1

Line No.	Month (a)	Actual Month (b)	Actual 12 Month (c)	Normal Month (d)	Normal 12 Month (e)	% of Normal (f)
1	9611	746		645		
2	9612	1,394		1,138		
3	9701	1,930		1,691		
4	9702	1,620		1,513		
5	9703	1,241		1,135		
6	9704	829		775		
7	9705	567		474		
8	9706	180		159		
9	9707	16		30		
10	9708	11		5		
11	9709	33		70		
12	9710	157	8,724	275	7,910	110.29%
13	9711	739	8,717	670	7,935	109.86%
14	9712	1,088	8,411	1,146	7,943	105.89%
15	9801	1,357	7,838	1,658	7,910	99.09%
16	9802	1,232	7,450	1,479	7,876	94.59%
17	9803	1,080	7,289	1,187	7,928	91.94%
18	9804	817	7,277	828	7,981	91.18%
19	9805	304	7,014	426	7,933	88.42%
20	9806	111	6,945	143	7,917	87.72%
21	9807	17	6,946	30	7,917	87.74%
22	9808	0	6,935	5	7,917	87.60%
23	9809	87	6,989	78	7,925	88.19%
24	9810	250	7,082	294	7,944	89.15%
25	9811	620	6,963	701	7,975	87.31%
26	9812	870	6,745	1,186	8,015	84.15%

Exhibit___(JJD-2)
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NORTHWESTERN PUBLIC SERVICE
1998 HEATING DEGREE DAYS

Exhibit___(JJD-3)
Page 1 of 1

ABERDEEN	ACTUAL	NORMAL	DEPARTURE	VARIANCE %
JANUARY	1,586	1,702	(116)	-6.82%
FEBRUARY	1,025	1,352	(327)	-24.19%
MARCH	1,229	1,091	138	12.65%
APRIL	503	594	(91)	-15.32%
MAY	182	269	(87)	-32.34%
JUNE	114	68	46	67.65%
JULY	1	15	(14)	-93.33%
AUGUST	0	29	(29)	-100.00%
SEPTEMBER	107	195	(88)	-45.13%
OCTOBER	511	549	(38)	-6.92%
NOVEMBER	947	1,041	(94)	-9.03%
DECEMBER	1,299	1,541	(242)	-15.70%
	7,504	8,446	(942)	-11.15%

HURON	ACTUAL	NORMAL	DEPARTURE	VARIANCE %
JANUARY	1,443	1,606	(163)	-10.15%
FEBRUARY	916	1,277	(361)	-28.27%
MARCH	1,157	1,026	131	12.77%
APRIL	476	561	(85)	-15.15%
MAY	135	256	(121)	-47.27%
JUNE	88	48	40	83.33%
JULY	0	10	(10)	-100.00%
AUGUST	0	22	(22)	-100.00%
SEPTEMBER	71	173	(102)	-58.96%
OCTOBER	422	512	(90)	-17.58%
NOVEMBER	851	978	(127)	-12.99%
DECEMBER	1,213	1,454	(241)	-16.57%
	6,772	7,923	(1,151)	-14.53%

SIOUX FALLS	ACTUAL	NORMAL	DEPARTURE	VARIANCE %
JANUARY	1,403	1,587	(184)	-11.59%
FEBRUARY	922	1,268	(346)	-27.29%
MARCH	1,138	1,008	130	12.90%
APRIL	548	543	5	0.92%
MAY	147	240	(93)	-38.75%
JUNE	117	50	67	134.00%
JULY	4	10	(6)	-60.00%
AUGUST	2	22	(20)	-90.91%
SEPTEMBER	79	165	(86)	-52.12%
OCTOBER	440	508	(68)	-13.39%
NOVEMBER	881	960	(79)	-8.23%
DECEMBER	1,262	1,448	(186)	-12.85%
	6,943	7,809	(866)	-11.09%

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	Docket No. NG99-____
NORTHWESTERN PUBLIC SERVICE	)	
a division of NorthWestern Corporation	)	

DIRECT TESTIMONY
OF
THOMAS P. HITCHCOCK

Q. **Please state your name, occupation and business address.**

A. My name is Thomas P. Hitchcock. I am Executive Vice President of NorthWestern Energy Corporation ("NEC"). My business address is 33 Third Street SE, Huron, South Dakota 57350.

Q. **Please describe your professional background and experience.**

A. I was graduated Magna Cum Laude from Kearney State College in 1975, now known as the University of Nebraska at Kearney, receiving a Bachelor of Science degree in Business Administration. In 1991, I attended the University of Michigan and completed their Public Utilities Executive Program.

In June, 1975 I accepted a position with Kansas-Nebraska Natural Gas Company (now known as KN Energy, Inc.) ("KNE") as an internal auditor in their Hastings, Nebraska office. While with KNE I held the positions of Senior Financial Analyst, Manager – Gas Accounting, Manager – Accounting Services and Director of Rates. Between 1983 and 1985 I held the position of Chief Accountant for Midlands Energy Company, an oil and gas

production affiliate of KNE spun-off to shareholders. Freeport-McMoRan, Inc. later acquired Midlands Energy Company. While employed by KNE, the majority of my work was accounting related, including rate analysis, cost of service studies, cost allocations, rate design, general ledger and accounting systems, tariff maintenance, financial reporting, strategic planning and budgeting. Major responsibilities in my last position at KNE included all aspects of rate and tariff filings with the Federal Energy Regulatory Commission, state and local jurisdictional authorities. I also supervised the consolidated accounting team for KNE, which included SEC and shareholder reporting functions.

In August, 1995 I accepted employment with NorthWestern Public Service ("NorthWestern"). My present responsibilities include the management of gas supply and regulation for NorthWestern's retail operations in South Dakota and Nebraska.

Q. What is the business relationship between NEC and NorthWestern?

A. NorthWestern is the regulated utility division of NorthWestern Corporation, while NEC is a wholly owned subsidiary of NorthWestern Corporation. NEC provides natural gas supply management and regulatory services for NorthWestern.

Q. Have you previously testified before the South Dakota Public Utilities Commission?

A. Yes, in prior proceedings dealing with the marketing affiliate rulemaking, a MidAmerican Energy gas cost adjustment hearing and NorthWestern's filing to true-up the Manufactured Gas Plant removal cost.

Q. Have you provided testimony in any other rate proceedings before other regulatory authorities?

A. Yes. I have testified before the Federal Energy Regulatory Commission, the Colorado

Public Utilities Commission, the Wyoming Public Service Commission and the Kansas Corporation Commission. I have also testified in various rate area hearings and court trials in Nebraska.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of NorthWestern Public Service ("NorthWestern" or "Company").

Q. Please state the nature of your testimony in this proceeding.

A. The purpose of my prepared direct testimony is to set forth information to determine the South Dakota Gas Revenue Requirement for NorthWestern. I have also prepared a class cost of service study for gas utility operations within the South Dakota jurisdiction. In addition, I will provide testimony supporting NorthWestern's rate design in this docket. I will also support NorthWestern's proposed rate tariffs. Finally, I will support all Statements and Schedules included in this filing not sponsored by another Company witness.

Q. Is NorthWestern filing gas rate cases in all of its state jurisdictions?

A. Yes, NorthWestern is filing gas rate cases in both South Dakota and Nebraska using the same test year and similar pro forma adjustments to the extent applicable to each jurisdiction. NorthWestern is having the revenue requirements of all gas jurisdictions determined using the most consistent basis as the mechanics of the ratemaking process allows.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes, I am sponsoring two exhibits related to my testimony in this case, Exhibit Nos.__(TPH-1) and (TPH-2). Various schedules are included as part of these exhibits, including the details of all the operating income statement and rate base adjustments.

Exhibit__(TPH-1) sets forth the South Dakota Gas Revenue Requirements study and Exhibit__(TPH-2) is the South Dakota jurisdiction class cost of service study.

Q. **Were these exhibits prepared by you or under your direction and supervision?**

A. Yes, they were. Certain pro forma adjustments to operating income are supported by other NorthWestern witnesses. I address those witnesses under the discussion of the pro forma.

Q. **Do these exhibits reflect the information shown on NorthWestern's books and records for the corresponding base period?**

A. Yes. The information shown per books, or actual, was taken from the books and records of NorthWestern for the base period consisting of the twelve-month period ended December 31, 1998. The historical base period amounts were adjusted for known and measurable changes expected to occur during the time proposed rates go into effect.

Revenue Requirements Study

Q. **What is contained in Exhibit__(TPH-1)?**

A. Exhibit__(TPH-1) is the South Dakota Gas Revenue Requirements study. A total of eleven major schedules are contained in this exhibit.

Q. **What is contained in Exhibit__(TPH-1), Schedule No. 1?**

A. Schedule No. 1 of this exhibit is the Financial Summary, which sets forth the South Dakota Gas Operating Income Statement with Pro Forma Adjustments. This shows, on a summary basis:

1. The 1998 base year South Dakota Gas operating revenues and expenses as included on the Company's 1998 Books and Records (Column (c));

2. The pro forma adjustments needed to reflect known and measurable changes used to

determine the level of revenues and expenses for ratemaking purposes (Column (d));

3. The adjusted and normalized base year operating income (Column (e));

4. The revenue adjustment required to have Adjusted Test Year Operating Income match the requested return (Column (f)); and

5. The South Dakota Gas Operating Income Statement with the proposed revenue adjustment (Column (g)).

Q. Please explain what is contained on Exhibit__(TPH-1), Schedule No. 1.1.

A. Schedule No. 1.1, consisting of 2 pages, summarizes the individual pro forma adjustments to revenues and expenses, showing the effect on operating income of each of the adjustments made to the Company's books and records to arrive at the appropriate revenues and expenses for revenue requirements purposes.

Q. Please explain what is contained on Exhibit__(TPH-1), Schedule No. 1.2.

A. Schedule No. 1.2, consisting of 1 page, summarizes the individual pro forma adjustments to rate base. The schedule shows the effect on South Dakota gas rate base of each of the known and measurable pro forma adjustments made to the Company's books and records for purposes of arriving at the appropriate rate base for this ratemaking proceeding.

Q. Would you briefly summarize what is contained on the other schedules included as part of Exhibit__(TPH-1).

A. Schedule No. 2, consisting of 3 pages, is a summary of gas sales and transportation revenues, containing actual base year billing units and revenues. Revenues have been broken down into type of revenue recovery, customer charges, distribution delivery charges,

ad valorem tax adjustment clause, MGP removal cost adjustment and gas costs. In addition, test year billing units are shown with associated revenues derived using present and proposed rates.

Schedule No. 2.1, consisting of 9 pages, contains the weather normalization of billing unit results. Each page sets forth revenues at base year actual, present and proposed rates by rate schedule. NorthWestern witness Decker sponsors testimony on the weather normalization adjustment made to each rate schedule.

Schedule No. 2.1.a, consisting of 3 pages, sets forth the revenues derived from customers with contracts with deviations.

Schedule No. 2.2, consisting of 1 page, contains the monthly heating degrees for Huron, South Dakota. NorthWestern witness Decker supports this schedule.

Schedule No. 3, consisting of 1 page, sets forth the details of other revenues, by account, during the base period and two years prior to the base period.

Schedule No. 4, consisting of 3 pages, contains base period unadjusted and test period adjusted operations and maintenance expenses by account.

Schedule Nos. 4.1 through 4.6, consisting a total of 18 pages, contains more particulars on the operations and maintenance expense accounts. Specifically, the schedules contain information broken down between direct and common costs. Schedule Nos. 4.2 and 4.6 contain the particulars on the allocation of common costs to South Dakota Gas, for both the base year actual and test year adjusted.

Schedule No. 5, consisting of 1 page, contains information on the Company's depreciation and amortization expense. This schedule also contains the allocation of

common depreciation to South Dakota Gas.

Schedule No. 6, consisting of 1 page, shows the particulars on the Company's taxes other than income taxes expense.

Schedule No. 7, consisting of 1 page, shows the computation of income taxes. A 35% Federal tax rate was assumed in all calculations.

Schedule No. 8, consisting of 1 page, sets forth the Company's estimate of rate case expense in this proceeding, along with the related adjustment to rate base for the unamortized rate case expense.

Schedule No. 9, consisting of 1 page, contains the computation of rate base and return.

Schedule No. 9.1, consisting of 2 pages, shows the book balances of plant accounts as of December 31, 1997 and 1998, along with base and test year adjusted thirteen-month average balances.

Schedule No. 9.2, consisting of 1 page, contains the consolidated capital structure of NorthWestern Corporation, and the computation of the cost of capital used in this docket. NorthWestern witness Leyendecker sponsors information contained on this schedule.

Schedule No. 9.3, consisting of 5 pages, contains the calculation of the thirteen-month average balance for certain rate base items, including any allocation of common cost to South Dakota Gas.

Schedule No. 9.4, consisting of 1 page, contains the calculation of the thirteen-month average balance for accumulated depreciation and amortization expense.

Schedule No. 10, consisting of 1 page, sets forth the common or indirect allocation

factors for the test period. These factors have been based on actual 1998 data, and are used to allocate common or indirect costs during 1999 and the adjusted test period. Schedule No. 11 is very similar to Schedule No. 10; it sets forth the actual base period allocation factors.

Pro Forma Adjustments – Operating Income Statement

Q. **Mr. Hitchcock, can you please refer back to Schedule No. 1.1 of Exhibit__(TPH-1)? Would you please explain each individual pro forma adjustment to the operating income statement?**

A. **Adjustment No. 1 – Weather Normalization**

Details and calculation of this adjustment are shown on Schedule Nos. 2.1 and 2.2. This adjustment decreases the revenue requirement by $615,283.

NorthWestern has made certain adjustments to base year volumes in determining test year volumes. The upward adjustment to base year volumes delivered to retail customers is primarily the result of warmer than normal weather in the base year. Heating degree-days during the base year were approximately 85 percent of normal. NorthWestern witness Decker sponsors this adjustment in his testimony. In summary, actual base year volumes were divided into temperature sensitive and non-temperature sensitive volumes. The non-temperature sensitive volume was determined using the August and September 1998 volumes in the base period. The temperature sensitive volume for the year was then calculated by subtracting the non-temperature sensitive volume from the total volume. The temperature sensitive volumes are normalized in a linear manner adjusting the base period temperature sensitive volumes by the ratio of historical normal heating degree days to the actual heating degree days matched to billing

cycles during the twelve months ended December 31, 1998.

This adjustment also determines the gas supply cost, ad valorem tax and MGP removal cost adjustments using weather normalized sales requirements and the cost component of each rate schedule in effect on May 2, 1999.

Adjustment No. 2 – New Customer Gas Load

Details and calculation of this adjustment are shown on Schedule No. 2.1, pages 8 and 9. This adjustment decreases the revenue requirement by $156,558.

This adjustment is the result of increasing test period volumes to three large commercial customers. These increased loads have come on in the last 12 months or will start during 1999.

Adjustment No. 3 – Other Revenues

Details and calculation of this adjustment are shown on Schedule No. 3. This adjustment decreases the revenue requirement by $34,469.

This adjustment is made to derive a more representative level of test year miscellaneous gas service revenues, based on three-year average actual revenues for the period ending December 31, 1998.

Adjustment No. 4 – Rate Case Expense

Details and calculation of this adjustment are shown on Schedule No. 8. This adjustment increases the revenue requirement by $50,000.

NorthWestern has included estimated rate case expense of $150,000 for this filing. This level of cost is proposed to be amortized into expense equally over a 3-year period. Included in this estimate of cost are consultant and other outside expense of

$50,000 and SDPUC rate case fund costs in the amount of $100,000. This level of cost is proposed to be trued-up to actual at the conclusion of this proceeding. This adjustment is consistent with prior ratemaking treatment.

Adjustment No. 5 – LP Gas Expense

Details and calculation of this adjustment are shown on Schedule No. 4.3. This adjustment decreases the revenue requirement by $132.

This adjustment is made to reflect the LP gas cost recovered through the gas cost adjustment clause.

Adjustment No. 6 – Advertising Expense

Details and calculation of this adjustment are shown on Schedule No. 4.4. This adjustment decreases the revenue requirement by $106,135.

This adjustment is made to reflect the elimination of known and measurable promotional and institutional advertising expense originally booked as a utility operating expense. The total cost reduction for these expenditures are $492,945. South Dakota's gas operations share of this elimination of cost was calculated using common allocation factors in effect during 1998. This adjustment is consistent with prior ratemaking treatment.

Adjustment No. 7 – Labor Expense

Details and calculation of this adjustment are shown on Schedule Nos. 4, 4.3 and 4.4. This adjustment increases the revenue requirement by $97,305.

NorthWestern has adjusted actual base year labor allocated or directly charged to South Dakota operations in the amount of $3,243,507 by 3 percent. This falls into the

average range of recent annual salary adjustments to employees.

Adjustment No. 8 – Common Allocation Factors

Details and calculation of this adjustment are shown on Schedule Nos. 4.2, 4.6, 5, 6, 10 and 11. This adjustment decreases the revenue requirement by $357,016.

This pro forma outlines the impact of updating the basis used to allocate common costs between electric and gas, and further between Nebraska and South Dakota gas. The company uses principles of allocation previously reviewed by the South Dakota Public Utilities Commission in prior gas cases. Depending on the type of common cost, amounts are allocated based on factors developed using customer counts, revenues, plant investment, labor charges, etc. This adjustment is the result of the Company allocating base year common costs by updated allocation factors to be used to allocate 1999 common costs. These factors are set forth on Schedule Nos. 10 and 11. Company employees have the ability and are encouraged to directly charge costs to a service and jurisdiction when the costs are specifically identifiable to that jurisdiction. Costs not directly assigned are allocated using different bases. This allocation basis, which is often referred to as the common allocation, is used to distribute a variety of costs, including plant and related depreciation reserves, between gas and electric service and the jurisdictions served by NorthWestern Public Service.

Adjustment No. 9 – Affiliate Management Fees

Details and calculation of this adjustment are shown on Schedule No. 4.4. This adjustment decreases the revenue requirement by $315,005.

This adjustment is made to reflect the known and measurable change to annual

customer assistance expense related to a reduction in the management fee from the Company's affiliated partner entity, NorthWestern Services. NorthWestern Services provides customer service, including call center operations and personnel, to NorthWestern Public Service for an annual management fee. The contract between the two entities for these services has been reduced to an annual level of $2.5 million, beginning January 1, 1999. The total reduction in annual cost to NorthWestern Public Service is $1,089,884. South Dakota's gas operations share of this reduction was calculated using common allocation factors in effect during 1998. NorthWestern witness Monaghan addresses changes in NorthWestern's corporate structure during 1998.

Adjustment No. 10 – Interest Synchronization

This adjustment shows the increase in Federal income taxes by using the interest synchronization method of computing the interest deduction for income tax purposes. This is consistent with prior ratemaking treatment.

Pro Forma Adjustments – Gas Rate Base

Q. **Would you please explain each individual pro forma adjustment to rate base, summarized on Schedule No. 1.2 of Exhibit__(TPH-1).**

A. **Adjustment No. 1 – Rate Case Expense**

Details and calculation of this adjustment are shown on Schedule No. 8. This adjustment increases rate base by $125,000 with an associated revenue requirement impact of $15,687 for return and associated income taxes.

This pro forma adjustment to rate base is the result of including in rate base the unamortized portion of rate case expense estimated in operating income statement

Adjustment No. 4. This is consistent with prior ratemaking treatment.

Adjustment No. 2 – Common Allocation Factors

Details and calculation of this adjustment are shown on Schedule Nos. 9, 9.3, 9.4, 10 and 11. This adjustment decreases rate base by $959,525, with an associated revenue requirement impact of $120,421 for return and associated income taxes.

As discussed in operating income statement Adjustment No. 8, this adjustment to rate base is the result of updating the common allocation factors to apply to common plant, related depreciation reserves, accumulated deferred income taxes and working capital.

Class Cost of Service Study

Q. What is the basis for the class cost of service study contained in Exhibit__(TPH-2)?

A. The study is based on South Dakota jurisdictional operations for the 12-month period ended December 31, 1998, as adjusted for known and measurable changes. All of the operating income statement and rate base figures are taken directly from the detail included in the previously mentioned revenue requirements study.

Q. What is the purpose of a class cost of service study?

A. A class cost of service study is an allocation to each rate schedule or class of customer of all revenues and costs relative to the furnishing of the utility service, including the appropriate assignment of revenues, operations and maintenance expenses, depreciation and other cost elements.

Q. Would you briefly describe the steps involved in preparing a class cost of service study?

A. The utility plant, revenue and expense accounts are examined and, where possible, amounts are assigned directly to certain classes of service or customers, based upon details derived from the books and records of the utility or by special analyses and studies. Amounts not directly assigned are analyzed by functional responsibility and groupings of accounts, such as production and distribution, then are allocated on the basis of demand, energy use and the number of customers associated with the various functional responsibilities.

Q. How would you describe your overall approach to the cost allocation study?

A. Since this was my first class cost of service study undertaken for NorthWestern, I reviewed the last cost allocation study filed with this Commission in Docket No. NG94-008. In addition, I reviewed MidAmerican Energy's most recent class cost of service study filed as part of their 1998 rate case, including the testimony of the PUC Staff witness. The resulting study undertaken in this filing generally applies cost allocation principles in a manner reasonably consistent with these studies.

Q. How are classes defined for the purpose of your class cost of service study?

A. My class cost of service study shows cost allocated to three service classes. Service classes are residential (Rate No. 81 – Residential Gas Service); small commercial (Rate No. 82 – General Gas Service); and large commercial (Rate Nos. 84 & 85 for sales service and Rate No. 87 for transportation service). Rates for large commercial accounts are offered under either an Option A or B. Option A service currently is chosen by large commercial accounts using generally less than 110,000 therms per year. This service rate option carries a smaller customer charge than Option B service, however, the non-gas commodity charge is approximately $0.02 per therm higher. The class cost of service study assumes all service

classes are firm, due to a continuing shift away from the sale of gas toward the transportation of gas. In the past, interruptible service was related to gas supply and pipeline constraints, not to the general capability of the distribution system.

Q. Please discuss the principal classification and allocations used in Exhibit__(TPH-2).

A. Pages 5 and 6 contain the development of the classification ratios of cost to either customer, demand or commodity, while the allocation ratios to customer class are shown on pages 7 and 8. Demand-related costs are those that relate to the utility's ability to meet and sustain the maximum gas flow required by customers. On NorthWestern's system, these days occur when it is extremely cold. Demand-related costs thus relate to the capacity that must be built into the system to meet peak operating conditions. Demand-related costs on NorthWestern's system include those associated with investments in peaking facilities and a substantial portion of distribution mains investment and related costs. In my study, I have classified 95 percent of distribution mains and 100 percent of peaking facilities as a demand-related cost. The demand-related costs are allocated on the basis of the February 1, 1996 requirements for each of the classes. The average temperature on that date was approximately 25 degrees Fahrenheit below zero. Due to mild weather the past two winters, this was selected as the most representative of design day peak conditions.

Q. How were most of the other distribution costs allocated?

A. Costs associated with meters, services and regulators were allocated on the basis of the number of customers, weighted to account for differences in cost for the size of customer. In general, expenses were allocated on the basis of the plant to which they relate. Supervision and engineering expenses were allocated on the basis of the other related O&M

accounts. Customer accounting expenses were allocated on the basis of weighted customers. Administrative and general costs, including common plant investment, were generally allocated in proportion to the allocation of distribution and production plant investment and expenses.

Q. **What are the results of the class cost of service study?**

A. The results are summarized on Pages 2 and 3 of the exhibit containing the study. Page 3 of the study shows, based on pro forma results at present rates, the following rates of return by class of customer:

Residential	5.50%
Small Commercial	5.18%
Large Commercial	6.18%

Shown on Page 2 of the study is the level of revenue requirement needed by each customer class to attain an overall rate of return requested by NorthWestern in this filing of 9.27%.

Q. **What are the principle conclusions you reach from your study?**

A. Based on results of my study, I find that existing gas revenues fail to cover South Dakota Gas jurisdictional revenue requirements by over $2.1 million. The cost of service study further indicates that the present increase required for the small commercial class is slightly above the overall increase, whereas the increases to the residential and large commercial classes are below the average.

Q. **What are the revenue deficiency amounts by class of customer and the percentage increase in non-gas cost revenue required?**

A. Residential $1,285,687 or 16.98% Increase

Small Commercial	494,413	or 22.56% Increase
Large Commercial	325,491	or 15.88% Increase
Total	$2,105,591	or 17.83% Increase

Q. **What accounts for the difference between the above total amount and the requested increase in revenues in the amount of $2,108,112?**

A. A $2,520 increase in customer charges allocated to those customers with a contract with deviations.

Q. **NorthWestern is filing for a gas rate increase in Nebraska on June 1, 1999. Is the method employed in Exhibit__(TPH-2) consistent with the method being used in that filing?**

A. Yes, it is.

Rate Design and Proposed Rates

Q. **Please explain NorthWestern's rate design goals in this Docket.**

A. NorthWestern's primary goal is that its prices for natural gas delivery service be cost-based and competitively priced to alternate fuel choices for customers. The revenues to be recovered by proposed rates are consistent with the class cost of service study results. In addition, I am proposing increases in all customer charges to move in the direction of the customer-based costs developed in my class cost of service study. For large commercial accounts, I am proposing a $50 customer charge differential between transportation and sales service. The primary reason for the increased charge to transportation (Rate No. 87) service is due to the extra costs incurred to maintain these accounts, such as those related to daily telemetering.

The class cost of service study results indicate that the small commercial class has the lowest rate of return and should therefore receive the greatest percentage increase. As a basic approach to apportioning the total requested increase of over $2.1 million, two considerations were utilized: first, to move every class to the system average return of 9.27 percent and, second, to give every class the same percentage increase in non-gas cost revenues at present rates. Because of the narrow range of rates of return, rates are designed to move every class to the system average return on 9.27 percent.

Q. Are you recommending a change to the current rate structure of NorthWestern's rate schedules?

A. No changes in rate structure are being recommended. The only changes being made are increases to the customer and non-gas cost delivery service charge component of rates.

Q. Please describe your proposed rate change for the residential class (Rate No. 81).

A. Overall proposed revenue increases for residential customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to increase its monthly customer charge for residential customers by $1.50 to $6.00. The class cost of service study indicates that a fully loaded customer charge for this type of account should be in the $14 per month range. The remaining increase, not collected via the proposed customer charge increase, was included in the distribution delivery commodity charge. More of the increase was put into the first rate block, to compensate for the entire customer related costs not being collected in the monthly customer charge.

Q. Please describe your proposed rate change for the small commercial class (Rate No. 82 or General Gas Service).

A. Overall proposed revenue increases for small commercial customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to increase its monthly customer charge for small commercial customers by $2.50 to $7.00. The class cost of service study indicates that a fully loaded customer charge for this type of account should be in the $16 per month range. The remaining increase, not collected via the proposed customer charge increase, was included in the distribution delivery commodity charge. More of the increase was put into the first rate block, to compensate for the entire customer related costs not being collected in the monthly customer charge.

Q. Please describe your proposed rate change for the large commercial class (Rate Nos. 84 and 85 – Sales and Rate No. 87 - Transportation).

A. Again, overall proposed revenue increases for large commercial customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to increase its monthly customer charge for large commercial customers by varying amounts depending upon the service and rate option. As explained above, transportation service is proposed to receive a higher customer charge. Proposed changes are as follows:

Rate Option A: Service under Rate Schedule Nos. 84 and 85

$10 per month increase to $80 per month charge

Rate Option B: Service under Rate Schedule Nos. 84 and 85

$20 per month increase to $280 per month charge.

Rate Option A: Service under Rate Schedule No 87

$60 per month increase to $130 per month charge

Rate Option B: Service under Rate Schedule Nos. 87

$70 per month increase to $330 per month charge

The remaining increase, not collected via the proposed customer charge increase, was included in the distribution delivery commodity charge.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

I, Thomas P. Hitchcock, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Thomas P. Hitchcock
Thomas P. Hitchcock

Subscribed and sworn to before me this 26th day of May, 1999.

Stacie Dowling 09/24/04
Notary Public in and for the State of South Dakota



NorthWestern Public Service
Financial Summary - South Dakota Gas
Twelve Months Ending December 31, 1998

Line No.	Description	Reference	Base Period Not Normalized	Base Period Normalizing Adjustments	Base Period Normalized	Adjustments to Reflect Requested Return	Test Period Total
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $
1	Operating Revenues						
2	Gas Sales Revenues	Sch 2, P2	28,608,395	3,457,409	32,065,804	1,910,866	33,976,670
3	Transportation Revenues	Sch 2, P3	1,066,888	360,459	1,427,347	197,246	1,624,593
4	Other Revenues	Sch 3, P1	129,402	34,521	163,923	0	163,923
5							
6	Total		29,804,685	3,852,389	33,657,074	2,108,112	35,765,186
7							
8	Operating Expenses						
9	Cost of Gas Supply	Sch 2, P2	18,996,521	2,487,993	21,484,514	0	21,484,514
10	MGP Removal Cost Adjustment	Sch 2, P2-3	1,094,543	223,907	1,318,450	(8,058)	1,310,392
11	Operating and Maintenance Expense	Sch 4, P3	6,324,871	(638,717)	5,686,154	0	5,686,154
12	Depreciation and Amortization	Sch 5, P1	1,659,056	(42,266)	1,616,790	0	1,616,790
13	Taxes Other Than Income Taxes	Sch 6, P1	675,670	298,187	973,857	3,162	977,019
14	Federal and State Income Taxes	Sch 7, P1	(52,222)	524,945	472,723	739,553	1,212,276
15	Rate Case Expense	Sch 8, P1	0	50,000	50,000	0	50,000
16							
17	Total		28,698,439	2,904,049	31,602,488	734,657	32,337,145
18							
19	Operating Income	Sch 9, P1	1,106,246	948,340	2,054,586	1,373,455	3,428,041
20							
21	Rate Base	Sch 9, P1	37,808,884	(834,525)	36,974,359	0	36,974,359
22							
23	Return on Rate Base		2.93%	2.63%	5.56%	3.71%	9.27%
24							
25	Return on Equity		-1.52%	5.30%	3.78%	7.47%	11.25%

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Exhibit___(TPH-1)
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NorthWestern Public Service
Summary of Pro Forma Adjustments - Operating Income Statement
Twelve Months Ending December 31, 1998

Schedule No. 1.1
Page 1 of 2

Adjustment No.		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Weather Normalization	New Customer Gas Load	Other Revenues	Rate Case Expense	LP Gas Expense	Advertising Expense	Labor Expense	Common Allocation Factors
	(a)	(b) $	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $
1	Operating Revenues								
2	Gas Sales Revenues	3,457,409	0	0	0	0	0	0	0
3	Transportation Revenues	64,860	295,599	0	0	0	0	0	0
4	Other Revenues	0	0	34,521	0	0	0	0	0
5									
6	Total	3,522,269	295,599	34,521	0	0	0	0	0
7									
8	Operating Expenses								
9	Cost of Gas Supply	2,487,993	0	0	0	0	0	0	0
10	MGP Removal Cost Adjustment	119,140	104,767	0	0	0	0	0	0
11	Operating and Maintenance Expense	0	0	0	0	(132)	(106,135)	97,305	(314,750)
12	Depreciation and Amortization	0	0	0	0	0	0	0	(42,266)
13	Taxes Other Than Income Taxes								
14	Ad Valorem	258,569	33,831	0	0	0	0	0	0
15	Gross Revenue	5,284	443	52	0	0	0	0	0
16	Other	0	0	0	0	0	0	0	8
17	Federal and State Income Taxes	227,949	54,795	12,064	(17,500)	46	37,147	(34,057)	124,953
18	Rate Case Expense	0	0	0	50,000	0	0	0	0
19									
20	Total	3,098,935	193,836	12,116	32,500	(86)	(68,988)	63,248	(232,055)
21									
22	Operating Income	423,334	101,763	22,405	(32,500)	86	68,988	(63,248)	232,055

Exhibit___(TPH-1)
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NorthWestern Public Service
Summary of Pro Forma Adjustments - Operating Income Statement
Twelve Months Ending December 31, 1998

Line No.	Description	Adjustment No.	(9) Affiliate Management Fees	(10) Interest Synchron.	(d)	(e)	(f)	(g)	(h)	(i)	Sch. No. 1 Col. (d) Total Adjustments
	(a)		(b) $	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $
1	Operating Revenues										
2	Gas Sales Revenues		0	0	0	0	0	0	0	0	3,457,409
3	Transportation Revenues		0	0	0	0	0	0	0	0	360,459
4	Other Revenues		0	0	0	0	0	0	0	0	34,521
5											
6	Total		0	0	0	0	0	0	0	0	3,852,389
7											
8	Operating Expenses										
9	Cost of Gas Supply		0	0	0	0	0	0	0	0	2,487,993
10	MGP Removal Cost Adjustment		0	0	0	0	0	0	0	0	223,907
11	Operating and Maintenance Expense		(315,005)	0	0	0	0	0	0	0	(638,717)
12	Depreciation and Amortization		0	0	0	0	0	0	0	0	(42,266)
13	Taxes Other Than Income Taxes										
14	Ad Valorem		0	0	0	0	0	0	0	0	292,400
15	Gross Revenue		0	0	0	0	0	0	0	0	5,779
16	Other		0	0	0	0	0	0	0	0	8
17	Federal and State Income Taxes		110,252	9,296	0	0	0	0	0	0	524,945
18	Rate Case Expense		0	0	0	0	0	0	0	0	50,000
19											
20	Total		(204,753)	9,296	0	0	0	0	0	0	2,904,049
21											
22	Operating Income		204,753	(9,296)	0	0	0	0	0	0	948,340

NorthWestern Public Service
Summary of Pro Forma Adjustments - Rate Base
Twelve Months Ending December 31, 1998

Schedule No. 1.2
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Adjustment No.		(1)	(2)							Sch. No. 9 Col. (d)
Line No.	Description	Rate Case Expense	Common Allocation Factors							Total Adjustments
	(a)	(b) $	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $
1	Plant in Service									
2	Direct South Dakota Gas Plant	0	0	0	0	0	0	0	0	0
3	Common Plant	0	(1,079,779)	0	0	0	0	0	0	(1,079,779)
4										
5	Subtotal	0	(1,079,779)	0	0	0	0	0	0	(1,079,779)
6										
7	Distribution Replacements									
8	Distribution Mains	0	0	0	0	0	0	0	0	0
9	Distribution Services	0	0	0	0	0	0	0	0	0
10	Construction in Service,									
11	Not Transferred									
12	Direct South Dakota Gas Plant	0	0	0	0	0	0	0	0	0
13	Common Plant	0	(21,985)	0	0	0	0	0	0	(21,985)
14										
15	Total Plant and Property	0	(1,101,764)	0	0	0	0	0	0	(1,101,764)
16										
17	Accumulated Depreciation & Amort.									
18	Direct South Dakota Gas Plant	0	0	0	0	0	0	0	0	0
19	Common Plant	0	(145,536)	0	0	0	0	0	0	(145,536)
20										
21	Total Reserve	0	(145,536)	0	0	0	0	0	0	(145,536)
22										
23	Net Utility Plant	0	(956,228)	0	0	0	0	0	0	(956,228)
24	Working Capital	0	0	0	0	0	0	0	0	0
25	Unamortized Rate Case Expense	125,000	0	0	0	0	0	0	0	125,000
26	Deferred Tax Reserve	0	(3,297)	0	0	0	0	0	0	(3,297)
27										
28	Net Rate Base	125,000	(959,525)	0	0	0	0	0	0	(834,525)

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NorthWestern Public Service
Summary of Gas Sales and Transportation Revenues
Twelve Months Ending December 31, 1998
South Dakota Gas

Schedule No. 2
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Line No.	Description	Reference	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Gas Sales Revenues**		No. of Bills			No. of Bills				
2	Customer Charges:									
3	Rate Code 81 - Residential	Sch 2.1, P1	400,847	$4.50	$1,803,812	400,847	$4.50	$1,803,812	$6.00	$2,405,082
4	Rate Code 82 - Small Commercial	Sch 2.1, P2	58,889	$4.50	$265,001	58,889	$4.50	$265,001	$7.00	$412,223
5	Rate Code 84 - Lg. Firm (Option A)	Sch 2.1, P3	1,963	$70.00	$137,410	1,963	$70.00	$137,410	$80.00	$157,040
6	Rate Code 84 - Lg. Firm (Option B)	Sch 2.1, P4	24	$260.00	$6,240	24	$260.00	$6,240	$280.00	$6,720
7	Rate Code 85 - Lg. Inter. (Option A)	Sch 2.1, P5	1,404	$70.00	$98,280	1,329	$70.00	$93,030	$80.00	$106,320
8	Rate Code 85 - Lg. Inter. (Option B)	Sch 2.1, P6	48	$260.00	$12,480	48	$260.00	$12,480	$280.00	$13,440
9	Totals		463,175		$2,323,223	463,100		$2,317,973		$3,100,825
10										
11										
12			Therms			Therms				
13	Distribution Delivery Charges:									
14	Rate Code 81 - Residential	Sch 2.1, P1	28,850,730	$0.1588	$4,581,878	33,197,790	$0.1441	$4,784,456	$0.1647	$5,468,873
15	Rate Code 82 - Small Commercial	Sch 2.1, P2	13,832,030	$0.1085	$1,500,985	15,832,990	$0.0978	$1,548,178	$0.1197	$1,895,369
16	Rate Code 84 - Lg. Firm (Option A)	Sch 2.1, P3	4,842,970	$0.0362	$175,327	5,505,570	$0.0364	$200,403	$0.0462	$254,199
17	Rate Code 84 - Lg. Firm (Option B)	Sch 2.1, P4	364,500	$0.0185	$6,742	430,450	$0.0180	$7,748	$0.0225	$9,685
18	Rate Code 85 - Lg. Inter. (Option A)	Sch 2.1, P5	3,416,180	$0.0348	$113,879	3,937,730	$0.0364	$143,333	$0.0462	$181,810
19	Rate Code 85 - Lg. Inter. (Option B)	Sch 2.1, P6	428,430	$0.0177	$7,580	487,770	$0.0180	$8,760	$0.0225	$10,975
20	Totals		51,734,840		$6,391,391	59,392,300		$6,692,898		$7,820,911
21										
22	Ad Valorem Tax Adjustment Clause:									
23	Rate Code 81 - Residential	Sch 2.1, P1	7,749,420	$0.0150	$116,407	33,197,790	$0.0156	$517,886	$0.0156	$517,886
24	Rate Code 82 - Small Commercial	Sch 2.1, P2	3,723,860	$0.0095	$35,413	15,832,990	$0.0099	$156,747	$0.0099	$156,747
25	Rate Code 84 - Lg. Firm (Option A)	Sch 2.1, P3	1,234,890	$0.0061	$7,484	5,505,570	$0.0064	$35,236	$0.0064	$35,236
26	Rate Code 84 - Lg. Firm (Option B)	Sch 2.1, P4	78,990	$0.0042	$331	430,450	$0.0042	$1,808	$0.0042	$1,808
27	Rate Code 85 - Lg. Inter. (Option A)	Sch 2.1, P5	1,987,000	$0.0063	$12,445	3,937,730	$0.0064	$25,201	$0.0064	$25,201
28	Rate Code 85 - Lg. Inter. (Option B)	Sch 2.1, P6	216,510	$0.0041	$892	487,770	$0.0042	$2,049	$0.0042	$2,049
29	Totals		14,990,670		$172,972	59,392,300		$738,927		$738,927

NorthWestern Public Service
Summary of Gas Sales and Transportation Revenues
Twelve Months Ending December 31, 1998
South Dakota Gas

Line No.	Description	Reference	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Gas Sales Revenues**		Therms			Therms				
2	MGP Removal Cost Adjustment:									
3	Rate Code 81 - Residential	Sch 2.1, P1	28,850,730	$0.0140	$403,910	33,197,790	$0.0140	$464,769	$0.0140	$464,769
4	Rate Code 82 - Small Commercial	Sch 2.1, P2	13,832,030	$0.0140	$193,648	15,832,990	$0.0140	$221,662	$0.0140	$221,662
5	Rate Code 84 - Lg. Firm (Option A)	Sch 2.1, P3	4,842,970	$0.0140	$67,802	5,505,570	$0.0140	$77,078	$0.0140	$77,078
6	Rate Code 84 - Lg. Firm (Option B)	Sch 2.1, P4	364,500	$0.0140	$5,103	430,450	$0.0140	$6,026	$0.0140	$6,026
7	Rate Code 85 - Lg. Inter. (Option A)	Sch 2.1, P5	3,416,180	$0.0140	$47,827	3,937,730	$0.0140	$55,128	$0.0140	$55,128
8	Rate Code 85 - Lg. Inter. (Option B)	Sch 2.1, P6	428,430	$0.0140	$5,998	487,770	$0.0140	$6,829	$0.0140	$6,829
9	Totals		51,734,840		$724,288	59,392,300		$831,492		$831,492
10										
11	Gas Cost Charges:									
12	Rate Code 81 - Residential	Sch 2.1, P1	28,850,730	$0.3882	$11,201,002	33,197,790	$0.3801	$12,618,479	$0.3801	$12,618,479
13	Rate Code 82 - Small Commercial	Sch 2.1, P2	13,832,030	$0.3881	$5,368,489	15,832,990	$0.3801	$6,018,120	$0.3801	$6,018,120
14	Rate Code 84 - Lg. Firm (Option A)	Sch 2.1, P3	4,842,970	$0.2969	$1,437,678	5,505,570	$0.2993	$1,648,010	$0.2993	$1,648,010
15	Rate Code 84 - Lg. Firm (Option B)	Sch 2.1, P4	364,500	$0.2649	$96,564	430,450	$0.2687	$115,672	$0.2687	$115,672
16	Rate Code 85 - Lg. Inter. (Option A)	Sch 2.1, P5	3,416,180	$0.2322	$793,299	3,937,730	$0.2447	$963,754	$0.2447	$963,754
17	Rate Code 85 - Lg. Inter. (Option B)	Sch 2.1, P6	428,430	$0.2322	$99,489	487,770	$0.2470	$120,479	$0.2470	$120,479
18	Totals		51,734,840		$18,996,521	59,392,300		$21,484,514		$21,484,514
19										
20	Total Gas Sales Revenues		51,734,840	$0.5530	$28,608,395	59,392,300	$0.5399	$32,065,804	$0.5721	$33,976,669
21										
22										
23	**Gas Transportation Revenues**		No. of Bills			No. of Bills				
24	Customer Charges:									
25	Rate Code 87 - (Option A)	Sch 2.1, P7	237	$70.00	$16,590	312	$70.00	$21,840	$130.00	$40,560
26	Rate Code 87 - (Option B)	Sch 2.1, P8	493	$260.00	$128,180	588	$260.00	$152,880	$330.00	$194,040
27	Rate Code 87 - (CWD)	Sch 2.1, P9	36	$260.00	$9,360	36	$260.00	$9,360	$330.00	$11,880
28	Totals		766		$154,130	936		$184,080		$246,480
29										
30			Therms			Therms				
31	Distribution Delivery Charges:									
32	Rate Code 87 - (Option A)	Sch 2.1, P7	1,172,050	$0.0388	$45,430	1,329,490	$0.0364	$48,393	$0.0462	$61,384
33	Rate Code 87 - (Option B)	Sch 2.1, P8	20,293,140	$0.0196	$397,731	28,241,640	$0.0180	$508,350	$0.0225	$635,437
34	Rate Code 87 - (CWD)	Sch 2.1, P9	9,309,890	$0.0097	$90,659	10,400,310	$0.0069	$72,016	$0.0077	$80,074
35	Totals		30,775,080		$533,820	39,971,440		$628,759		$776,895

NorthWestern Public Service
Summary of Gas Sales and Transportation Revenues
Twelve Months Ending December 31, 1998
South Dakota Gas

Schedule No. 2
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Line No.	Description	Reference	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Gas Transportation Revenues**		Therms			Therms				
2	Ad Valorem Tax Adjustment Clause:									
3	Rate Code 87 - (Option A)	Sch 2.1, P7	523,710	$0.0062	$3,262	1,329,490	$0.0064	$8,509	$0.0064	$8,509
4	Rate Code 87 - (Option B)	Sch 2.1, P8	8,471,780	$0.0038	$32,032	28,241,640	$0.0042	$118,615	$0.0042	$118,615
5	Rate Code 87 - (CWD)	Sch 2.1, P9	3,741,910	$0.0037	$13,948	10,400,310	$0.0042	$43,682	$0.0042	$43,682
6	Totals		12,737,400		$49,242	39,971,440		$170,806		$170,806
7										
8	MGP Removal Cost Adjustment:									
9	Rate Code 87 - (Option A)	Sch 2.1, P7	1,172,050	$0.0140	$16,409	1,329,490	$0.0140	$18,613	$0.0140	$18,613
10	Rate Code 87 - (Option B)	Sch 2.1, P8	20,293,140	$0.0140	$284,104	28,241,640	$0.0140	$395,383	$0.0140	$395,383
11	Rate Code 87 - (CWD)	Sch 2.1, P9	9,309,890	$0.0075	$69,742	10,400,310	$0.0070	$72,962	$0.0062	$64,904
12	Totals		30,775,080		$370,255	39,971,440		$486,958		$478,900
13										
14	Extended Service Rider Adjusment:									
15	Rate Code 87 - (Option A)	Sch 2.1, P7			$0			$0		$0
16	Rate Code 87 - (Option B)	Sch 2.1, P8			($39,446)			($42,090)		($47,322)
17	Rate Code 87 - (CWD)	Sch 2.1, P9			($1,113)			($1,166)		($1,166)
18	Totals				($40,559)			($43,256)		($48,488)
19										
20	Total Gas Transportation Revenues		30,775,080	$0.0347	$1,066,888	39,971,440	$0.0357	$1,427,347	$0.0406	$1,624,593

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Residential - Rate Code 81

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			First 30	Over 30		
2			Therms	Therms		
3						
4	August 1998 Therm Units		445,110	42,450	0	487,560
5	September 1998 Therm Units		431,820	41,180	0	473,000
6						
7	Subtotal		876,930	83,630	0	960,560
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		5,261,580	501,780	0	5,763,360
11	Total Therm Units - Base Year		8,756,400	20,094,330	0	28,850,730
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,494,820	19,592,550	0	23,087,370
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,152,850	23,281,580	0	27,434,430
19	Add: Baseload Therms Above		5,261,580	501,780	0	5,763,360
20						
21	Total Therm Units - Test Year		9,414,430	23,783,360	0	33,197,790

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	400,847	$4.50	$1,803,812	400,847	$4.50	$1,803,812	$6.00	$2,405,082
29	Distribution Delivery Commodity Charge								
30	First 30 therms	8,756,400	$0.2136	$1,870,117	9,414,430	$0.2000	$1,882,886	$0.2474	$2,329,469
31	Over 30 therms	20,094,330	$0.1350	$2,711,761	23,783,360	$0.1220	$2,901,570	$0.1320	$3,139,404
32	Ad Valorem Tax Adjustment	7,749,420	$0.0150	$116,407	33,197,790	$0.0156	$517,886	$0.0156	$517,886
33	MGP Removal Cost Adjustment	28,850,730	$0.0140	$403,910	33,197,790	$0.0140	$464,769	$0.0140	$464,769
34	Gas Cost Commodity Charge	28,850,730	$0.2419	$6,980,315	33,197,790	$0.2043	$6,782,308	$0.2043	$6,782,308
35	Gas Cost Demand Charge	28,850,730	$0.1463	$4,220,687	33,197,790	$0.1758	$5,836,171	$0.1758	$5,836,171
36									
37	Totals	26,850,730		$18,107,009	33,197,790		$20,189,402		$21,475,089
38	Less: Gas Cost			$11,201,002			$12,618,479		$12,618,479
39									
40	Margin			$6,906,007			$7,570,923		$8,856,610

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Small Commercial - Rate Code 82

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			First 400	Next 1,600	Over 2,000	
2			Therms	Therms	Therms	
3						
4	August 1998 Therm Units		207,530	81,880	1,240	290,650
5	September 1998 Therm Units		193,870	48,470	1,160	243,500
6						
7	Subtotal		401,400	130,350	2,400	534,150
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		2,408,400	782,100	14,400	3,204,900
11	Total Therm Units - Base Year		7,526,830	5,234,330	1,070,870	13,832,030
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		5,118,430	4,452,230	1,056,470	10,627,130
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		6,082,170	5,290,530	1,255,390	12,628,090
19	Add: Baseload Therms Above		2,408,400	782,100	14,400	3,204,900
20						
21	Total Therm Units - Test Year		8,490,570	6,072,630	1,269,790	15,832,990

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	58,889	$4.50	$265,001	58,889	$4.50	$265,001	$7.00	$412,223
29	Distribution Delivery Commodity Charge								
30	First 400 therms	7,526,830	$0.1249	$940,440	8,490,570	$0.1141	$968,774	$0.1471	$1,248,890
31	Next 1,600 therms	5,234,330	$0.0941	$492,621	6,072,630	$0.0841	$510,708	$0.0941	$571,434
32	Over 2,000 therms	1,070,870	$0.0634	$67,924	1,269,790	$0.0541	$68,696	$0.0591	$75,045
33	Ad Valorem Tax Adjustment	3,723,860	$0.0095	$35,413	15,832,990	$0.0099	$156,747	$0.0099	$156,747
34	MGP Removal Cost Adjustment	13,832,030	$0.0140	$193,648	15,832,990	$0.0140	$221,662	$0.0140	$221,662
35	Gas Cost Commodity Charge	13,832,030	$0.2419	$3,345,923	15,832,990	$0.2043	$3,234,680	$0.2043	$3,234,680
36	Gas Cost Demand Charge	13,832,030	$0.1462	$2,022,566	15,832,990	$0.1758	$2,783,440	$0.1758	$2,783,440
37									
38	Totals	13,832,030		$7,363,536	15,832,990		$8,209,708		$8,704,121
39	Less: Gas Cost			$5,368,489			$6,018,120		$6,018,120
40									
41	Margin			$1,995,047			$2,191,588		$2,686,001

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Firm - Rate Code 84 (Option A)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		112,810	0	0	112,810
5	September 1998 Therm Units		107,840	0	0	107,840
6						
7	Subtotal		220,650	0	0	220,650
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		1,323,900	0	0	1,323,900
11	Total Therm Units - Base Year		4,842,970	0	0	4,842,970
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,519,070	0	0	3,519,070
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,181,670	0	0	4,181,670
19	Add: Baseload Therms Above		1,323,900	0	0	1,323,900
20						
21	Total Therm Units - Test Year		5,505,570	0	0	5,505,570
22						

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
23									
24									
25									
26									
27									
28	Customer Charge	1,963	$70.00	$137,410	1,963	$70.00	$137,410	$80.00	$157,040
29	Distribution Delivery Commodity Charge								
30	All therms	4,842,970	$0.0362	$175,327	5,505,570	$0.0364	$200,403	$0.0462	$254,199
31	Ad Valorem Tax Adjustment	1,234,890	$0.0061	$7,484	5,505,570	$0.0064	$35,236	$0.0064	$35,236
32	MGP Removal Cost Adjustment	4,842,970	$0.0140	$67,802	5,505,570	$0.0140	$77,078	$0.0140	$77,078
33	Gas Cost Commodity Charge	4,842,970	$0.2212	$1,071,243	5,505,570	$0.2300	$1,266,281	$0.2300	$1,266,281
34	Gas Cost Demand Charge	425,480	$0.8373	$356,265	425,480	$0.8700	$370,168	$0.8700	$370,168
35	Released Capacity/Balancing Surcharge	598,200	$0.0170	$10,170	680,040	$0.0170	$11,561	$0.0170	$11,561
36									
37	Totals	4,842,970		$1,825,701	5,505,570		$2,098,137		$2,171,563
38	Less: Gas Cost			$1,437,678			$1,648,010		$1,648,010
39									
40	Margin			$388,023			$450,127		$523,553

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Firm - Rate Code 64 (Option B)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		750	0	0	750
5	September 1998 Therm Units		1,620	0	0	1,620
6						
7	Subtotal		2,370	0	0	2,370
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		14,220	0	0	14,220
11	Total Therm Units - Base Year		364,500	0	0	364,500
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		350,280	0	0	350,280
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		416,230	0	0	416,230
19	Add: Baseload Therms Above		14,220	0	0	14,220
20						
21	Total Therm Units - Test Year		430,450	0	0	430,450
22						

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
23									
24									
25									
26									
27									
28	Customer Charge	24	$260.00	$6,240	24	$260.00	$6,240	$280.00	$6,720
29	Distribution Delivery Commodity Charge								
30	All therms	364,500	$0.0185	$6,742	430,450	$0.0180	$7,748	$0.0225	$9,685
31	Ad Valorem Tax Adjustment	78,990	$0.0042	$331	430,450	$0.0042	$1,808	$0.0042	$1,808
32	MGP Removal Cost Adjustment	364,500	$0.0140	$5,103	430,450	$0.0140	$6,026	$0.0140	$6,026
33	Gas Cost Commodity Charge	364,500	$0.2212	$80,626	430,450	$0.2300	$99,004	$0.2300	$99,004
34	Gas Cost Demand Charge	18,120	$0.8373	$15,172	18,120	$0.8700	$15,764	$0.8700	$15,764
35	Released Capacity/Balancing Charge	45,030	$0.0170	$766	53,180	$0.0170	$904	$0.0170	$904
36									
37	Totals	364,500		$114,980	430,450		$137,494		$139,911
38	Less: Gas Cost			$96,564			$115,672		$115,672
39									
40	Margin			$18,416			$21,822		$24,239

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Interruptible - Rate Code 85 (Option A)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		53,000	0	0	53,000
5	September 1998 Therm Units		54,700	0	0	54,700
6						
7	Subtotal		107,700	0	0	107,700
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		646,200	0	0	646,200
11	Total Therm Units - Base Year		3,416,180	0	0	3,416,180
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		2,769,980	0	0	2,769,980
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		3,291,530	0	0	3,291,530
19	Add: Baseload Therms Above		646,200	0	0	646,200
20						
21	Total Therm Units - Test Year		3,937,730	0	0	3,937,730

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	1,404	$70.00	$98,280	1,329	$70.00	$93,030	$80.00	$106,320
29	Distribution Delivery Commodity Charge								
30	All therms	3,416,180	$0.0348	$118,879	3,937,730	$0.0364	$143,333	$0.0462	$181,810
31	Ad Valorem Tax Adjustment	1,987,000	$0.0063	$12,445	3,937,730	$0.0064	$25,201	$0.0064	$25,201
32	MGP Removal Cost Adjustment	3,416,180	$0.0140	$47,827	3,937,730	$0.0140	$55,128	$0.0140	$55,128
33	Gas Cost Commodity Charge	3,416,180	$0.2152	$735,223	3,937,730	$0.2300	$905,678	$0.2300	$905,678
34	Released Capacity/Balancing Charge	3,416,180	$0.0170	$58,076	3,416,180	$0.0170	$58,076	$0.0170	$58,076
35									
36	Totals	3,416,180		$1,070,730	3,937,730		$1,280,446		$1,332,213
37	Less: Gas Cost			$793,299			$963,754		$963,754
38									
39	Margin			$277,431			$316,692		$368,459

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Large Commercial/Industrial Interruptible - Rate Code 85 (Option B)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		8,970	0	0	8,970
5	September 1998 Therm Units		9,910	0	0	9,910
6						
7	Subtotal		18,880	0	0	18,880
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		113,280	0	0	113,280
11	Total Therm Units - Base Year		428,430	0	0	428,430
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		315,150	0	0	315,150
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		374,490	0	0	374,490
19	Add: Baseload Therms Above		113,280	0	0	113,280
20						
21	Total Therm Units - Test Year		487,770	0	0	487,770

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	48	$260.00	$12,480	48	$260.00	$12,480	$280.00	$13,440
29	Distribution Delivery Commodity Charge								
30	All therms	428,430	$0.0177	$7,580	487,770	$0.0180	$8,780	$0.0225	$10,975
31	Ad Valorem Tax Adjustment	216,510	$0.0041	$892	487,770	$0.0042	$2,049	$0.0042	$2,049
32	MGP Removal Cost Adjustment	428,430	$0.0140	$5,998	487,770	$0.0140	$6,829	$0.0140	$6,829
33	Gas Cost Commodity Charge	428,430	$0.2152	$92,206	487,770	$0.2300	$112,187	$0.2300	$112,187
34	Released Capacity/Balancing Charge	428,430	$0.0170	$7,283	487,770	$0.0170	$8,292	$0.0170	$8,292
35									
36	Totals	428,430		$126,439	487,770		$150,317		$153,772
37	Less: Gas Cost			$99,489			$120,479		$120,479
38									
39	Margin			$26,950			$30,138		$33,293

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Rate Code 87 (Option A)

Line No.	Description		Block 1	Block 2	Block 3	Total
	(a)		(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		28,080	0	0	28,080
5	September 1998 Therm Units		27,900	0	0	27,900
6						
7	Subtotal		55,980	0	0	55,980
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		335,880	0	0	335,880
11	Total Therm Units - Base Year		1,172,050	0	0	1,172,050
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		836,170	0	0	836,170
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		993,610	0	0	993,610
19	Add: Baseload Therms Above		335,880	0	0	335,880
20						
21	Total Therm Units - Test Year		1,329,490	0	0	1,329,490
22						

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
23									
24									
25									
26									
27									
28	Customer Charge	237	$70.00	$16,590	312	$70.00	$21,840	$130.00	$40,560
29	Distribution Delivery Commodity Charge								
30	All therms	1,172,050	$0.0388	$45,430	1,329,490	$0.0364	$48,393	$0.0462	$61,384
31	Extended Service Rider Discount			$0			$0		$0
32	Ad Valorem Tax Adjustment	523,710	$0.0062	$3,262	1,329,490	$0.0064	$8,509	$0.0064	$8,509
33	MGP Removal Cost Adjustment	1,172,050	$0.0140	$16,409	1,329,490	$0.0140	$18,613	$0.0140	$18,613
34									
35	Totals	1,172,050		$81,691	1,329,490		$97,355		$129,066
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$81,691			$97,355		$129,066

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NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Rate Code 87 (Option B)

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		1,363,020	0	0	1,363,020
5	September 1998 Therm Units		1,356,620	0	0	1,356,620
6						
7	Subtotal		2,719,640	0	0	2,719,640
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		16,317,840	0	0	16,317,840
11	Total Therm Units - Base Year		20,293,140	0	0	20,293,140
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		3,975,300	0	0	3,975,300
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		4,723,800	0	0	4,723,800
19	Pro Forma New Load		7,200,000	0	0	7,200,000
20	Add: Baseload Therms Above		16,317,840	0	0	16,317,840
21						
22	Total Therm Units - Test Year		28,241,640	0	0	28,241,640
23						
24						
25			Base Year			Test Year		Test Year Revenues @		Test Year Revenues @
26	Revenue Recovery		Billing Determinants	Base Year Rates	Base Year Revenues	Billing Determinants	Present Rates	Present Rates	Proposed Rates	Proposed Rates
27			(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
28										
29	Customer Charge		493	$260.00	$128,180	588	$260.00	$152,880	$330.00	$194,040
30	Distribution Delivery Commodity Charge									
31	All therms		20,293,140	$0.0196	$397,731	28,241,640	$0.0180	$508,350	$0.0225	$635,437
32	Extended Service Rider Discount				($39,446)			($42,090)		($47,322)
33	Ad Valorem Tax Adjustment		8,471,780	$0.0038	$32,032	28,241,640	$0.0042	$118,615	$0.0042	$118,615
34	MGP Removal Cost Adjustment		20,293,140	$0.0140	$284,104	28,241,640	$0.0140	$395,383	$0.0140	$395,383
35										
36	Totals		20,293,140		$802,601	28,241,640		$1,133,138		$1,296,153
37	Less Gas Cost				$0			$0		$0
38										
39	Margin				$802,601			$1,133,138		$1,296,153

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		667,270	0	0	667,270
5	September 1998 Therm Units		675,900	0	0	675,900
6						
7	Subtotal		1,343,170	0	0	1,343,170
8	Times		6	6	6	5
9						
10	Baseload Therms - Annual		8,059,020	0	0	8,059,020
11	Total Therm Units - Base Year		9,309,890	0	0	9,309,890
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		1,250,870	0	0	1,250,870
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		1,486,390	0	0	1,486,390
19	Pro Forma New Load		854,900	0	0	854,900
20	Add: Baseload Therms Above		8,059,020	0	0	8,059,020
21						
22	Total Therm Units - Test Year		10,400,310	0	0	10,400,310
23						

		Base Year Billing	Base Year	Base Year	Test Year Billing	Present	Test Year Revenues @ Present	Proposed	Test Year Revenues @ Proposed
24									
25									
26	Revenue Recovery	Determinants	Rates	Revenues	Determinants	Rates	Rates	Rates	Rates
27		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
28									
29	Customer Charge	36	$260.00	$9,360	36	$260.00	$9,360	$330.00	$11,880
30	Distribution Delivery Commodity Charge								
31	All therms	9,309,890	$0.0097	$90,659	10,400,310	$0.0069	$72,016	$0.0077	$80,074
32	Extended Service Rider Discount			($1,113)			($1,166)		($1,166)
33	Ad Valorem Tax Adjustment	3,741,910	$0.0037	$13,948	10,400,310	$0.0042	$43,682	$0.0042	$43,682
34	MGP Removal Cost Adjustment	9,309,890	$0.0075	$69,742	10,400,310	$0.0070	$72,962	$0.0062	$64,904
35									
36	Totals	9,309,890		$182,596	10,400,310		$196,854		$199,374
37	Less: Gas Cost			$0			$0		$0
38									
39	Margin			$182,596			$196,854		$199,374

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
South Dakota Soybean Processors - Volga

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		418,330	0	0	418,330
5	September 1998 Therm Units		327,140	0	0	327,140
6						
7	Subtotal		745,470	0	0	745,470
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		4,472,820	0	0	4,472,820
11	Total Therm Units - Base Year		5,291,040	0	0	5,291,040
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		818,220	0	0	818,220
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		972,280	0	0	972,280
19	Pro Forma New Load		854,900	0	0	854,900
20	Add: Baseload Therms Above		4,472,820	0	0	4,472,820
21						
22	Total Therm Units - Test Year		6,300,000	0	0	6,300,000

23										
24			Base Year			Test Year		Test Year Revenues @		Test Year Revenues @
25			Billing	Base Year	Base Year	Billing	Present	Present	Proposed	Proposed
26	Revenue Recovery		Determinants	Rates	Revenues	Determinants	Rates	Rates	Rates	Rates
27			(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
28										
29	Customer Charge		12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
30	Distribution Delivery Commodity Charge									
31	All therms		5,291,040	$0.0056	$29,815	6,300,000	$0.0032	$19,908	$0.0037	$23,121
32	Extended Service Rider Discount				$0			$0		$0
33	Ad Valorem Tax Adjustment		2,205,550	$0.0038	$8,280	6,300,000	$0.0042	$26,460	$0.0042	$26,460
34	MGP Removal Cost Adjustment		5,291,040	$0.0048	$25,397	6,300,000	$0.0046	$29,232	$0.0041	$26,019
35										
36	Totals		5,291,040		$66,612	6,300,000		$78,720		$79,560
37	Less: Gas Cost				$0			$0		$0
38										
39	Margin				$66,612			$78,720		$79,560
40										
41	Total Commodity Rate =	$0.01200	per therm							

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
3M - Brookings

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		216,330	0	0	216,330
5	September 1998 Therm Units		312,020	0	0	312,020
6						
7	Subtotal		528,350	0	0	528,350
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		3,170,100	0	0	3,170,100
11	Total Therm Units - Base Year		3,462,260	0	0	3,462,260
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		292,160	0	0	292,160
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		347,170	0	0	347,170
19	Add: Baseload Therms Above		3,170,100	0	0	3,170,100
20						
21	Total Therm Units - Test Year		3,517,270	0	0	3,517,270

Line No.	Revenue Recovery	Base Year Billing Determinants	Base Year Rates	Base Year Revenues	Test Year Billing Determinants	Present Rates	Test Year Revenues @ Present Rates	Proposed Rates	Test Year Revenues @ Proposed Rates
		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
29	Distribution Delivery Commodity Charge								
30	All therms	3,462,260	$0.0154	$53,290	3,517,270	$0.0130	$45,619	$0.0142	$49,840
31	Extended Service Rider Discount			$0			$0		$0
32	Ad Valorem Tax Adjustment	1,325,790	$0.0037	$4,873	3,517,270	$0.0042	$14,773	$0.0042	$14,773
33	MGP Removal Cost Adjustment	3,462,260	$0.0112	$38,779	3,517,270	$0.0108	$38,092	$0.0096	$33,871
34									
35	Totals	3,462,260		$100,062	3,517,270		$101,604		$102,444
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$100,062			$101,604		$102,444
39									
40	Total Commodity Rate =	$0.02600	per therm						

NorthWestern Public Service
Normalization of Billing Units - Therms and Revenues
Twelve Months Ending December 31, 1998
South Dakota Transportation - Contracts with Deviations
Saputo Cheese - Big Stone

Line No.	Description	Reference	Block 1	Block 2	Block 3	Total
	(a)	(b)	(c)	(d)	(e)	(f)
1			All			
2			Therms			
3						
4	August 1998 Therm Units		32,610	0	0	32,610
5	September 1998 Therm Units		36,740	0	0	36,740
6						
7	Subtotal		69,350	0	0	69,350
8	Times		6	6	6	6
9						
10	Baseload Therms - Annual		416,100	0	0	416,100
11	Total Therm Units - Base Year		556,590	0	0	556,590
12						
13	Base Year Actual Heating Degree					
14	Day (HDD) Sensitive Therms		140,490	0	0	140,490
15	Times Normal HDDs	Sch 2.2	8,015	8,015	8,015	8,015
16	Divide by Actual HDDs	Sch 2.2	6,745	6,745	6,745	6,745
17						
18	Normalized HDD Sensitive Therms		166,940	0	0	166,940
19	Add: Baseload Therms Above		416,100	0	0	416,100
20						
21	Total Therm Units - Test Year		583,040	0	0	583,040

Line No.	Revenue Recovery	Base Year Billing Determinants (c)	Base Year Rates (d)	Base Year Revenues (e)	Test Year Billing Determinants (f)	Present Rates (g)	Test Year Revenues @ Present Rates (h)	Proposed Rates (i)	Test Year Revenues @ Proposed Rates (j)
22									
23									
24									
25									
26									
27									
28	Customer Charge	12	$260.00	$3,120	12	$260.00	$3,120	$330.00	$3,960
29	Distribution Delivery Commodity Charge								
30	All therms	556,590	$0.0136	$7,554	583,040	$0.0111	$6,489	$0.0122	$7,113
31	Extended Service Rider Discount			($1,113)			($1,166)		($1,166)
32	Ad Valorem Tax Adjustment	210,570	$0.0038	$795	583,040	$0.0042	$2,449	$0.0042	$2,449
33	MGP Removal Cost Adjustment	556,590	$0.0100	$5,566	583,040	$0.0097	$5,638	$0.0086	$5,014
34									
35	Totals	556,590		$15,922	583,040		$16,530		$17,370
36	Less: Gas Cost			$0			$0		$0
37									
38	Margin			$15,922			$16,530		$17,370
39									
40	Total Commodity Rate =	$0.02500	per therm						

NorthWestern Public Service
Normalization of Billing Units - Heating Degree Days
Huron, South Dakota

Line No.	Month	Actual		Normal		% of
		Month	12 Month	Month	12 Month	Normal
	(a)	(b)	(c)	(d)	(e)	(f)
1	9611	746		645		
2	9612	1,394		1,138		
3	9701	1,930		1,691		
4	9702	1,620		1,513		
5	9703	1,241		1,135		
6	9704	829		775		
7	9705	567		474		
8	9706	180		159		
9	9707	16		30		
10	9708	11		5		
11	9709	33		70		
12	9710	157	8,724	275	7,910	110.29%
13	9711	739	8,717	670	7,935	109.86%
14	9712	1,088	8,411	1,146	7,943	105.89%
15	9801	1,357	7,838	1,658	7,910	99.09%
16	9802	1,232	7,450	1,479	7,876	94.59%
17	9803	1,080	7,289	1,187	7,928	91.94%
18	9804	817	7,277	828	7,981	91.18%
19	9805	304	7,014	426	7,933	88.42%
20	9806	111	6,945	143	7,917	87.72%
21	9807	17	6,946	30	7,917	87.74%
22	9808	0	6,935	5	7,917	87.60%
23	9809	87	6,989	78	7,925	88.19%
24	9810	250	7,082	294	7,944	89.15%
25	9811	620	6,963	701	7,975	87.31%
26	9812	870	6,745	1,186	8,015	84.15%

NorthWestern Public Service
Other Revenues
Twelve Months Ending December 31, 1998

Schedule No. 3
Page 1 of 1

Line No.	Description	Account No.	Actual Base Period	Adjustments	Test Period	Base Period	One Year Prior to Base Period	Two Years Prior to Base Period	Three Year Average
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $
1	Late Payment Charges	487	61,856	28,902	90,758	61,856	109,472	100,945	90,758
2									
3	Miscellaneous Service Charges	488	66,252	6,204	72,456	66,252	80,318	70,798	72,456
4									
5	Other Gas Revenues	495	1,294	(585)	709	1,294	378	454	709
6									
7	Total Other Revenues		129,402	34,521	163,923	129,402	190,168	172,197	163,923

Exhibit___(TPH-1)
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NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998

Line No.	Description	Account No.	Schedule No. 4.5 Base Period Twelve Months Ended December 31, 1998 Total	Labor	Other	Adjustments Labor	Other	Schedule No. 4.1 Test Period Adjusted for Known & Measurable Changes Total	Labor	Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $
1	Gas Production Expenses									
2	Operations:									
3	Supervision and Engineering	710	13,407	11,986	1,421	151	(11)	13,547	12,137	1,410
4	LP Gas Expense	717	446	409	37	12	0	458	421	37
5	Fuel	723	2,656	0	2,656	0	0	2,656	0	2,656
6	LP Gas	728	132	0	132	0	(132)	0	0	0
7	Miscellaneous	735	1,959	892	1,067	27	0	1,986	919	1,067
8										
9	Total Operations		18,600	13,287	5,313	190	(143)	18,647	13,477	5,170
10										
11	Maintenance:									
12	Supervision and Engineering	740	10,134	9,006	1,128	132	(7)	10,259	9,138	1,121
13	Structures	741	2,240	2,172	68	65	0	2,305	2,237	68
14	Production Equipment	742	1,411	0	1,411	0	0	1,411	0	1,411
15										
16	Total Maintenance		13,785	11,178	2,607	197	(7)	13,975	11,375	2,600
17										
18	Distribution Expenses									
19	Operations:									
20	Supervision and Engineering	870	432,091	195,180	236,911	4,745	(125)	436,711	199,925	236,786
21	Load Dispatching	871	120,984	76,617	44,367	(2,781)	(2,958)	115,245	73,836	41,409
22	Compressor Station Expenses	872	0	0	0	0	0	0	0	0
23	Mains and Services Expenses	874	423,221	147,965	275,256	4,436	(1,108)	426,549	152,401	274,148
24	Meas and Reg Station Exp-Gen	875	15,518	12,923	2,595	388	0	15,906	13,311	2,595
25	Meas and Reg Station Exp-Industrial	876	0	0	0	0	0	0	0	0
26	Meas and Reg Station Exp-City Gate	877	42,848	34,339	8,509	1,030	0	43,878	35,369	8,509
27	Meter and House Regulator Expense	878	244,014	259,213	(15,199)	7,776	6,298	258,088	266,989	(8,901)
28	Customer Installation Expense	879	(174,727)	45,591	(220,318)	1,354	14,333	(159,040)	46,945	(205,985)
29	Other Expense	880	257,806	222,875	34,931	5,136	(653)	262,289	228,011	34,278
30	Rents	881	4,829	0	4,829	0	(328)	4,501	0	4,501
31										
32	Total Operations		1,386,584	994,703	371,881	22,084	15,459	1,404,127	1,016,787	387,340

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998

Line No.	Description	Account No.	Schedule No. 4.5 Base Period Twelve Months Ended December 31, 1998 Total	Labor	Other	Adjustments Labor	Other	Schedule No. 4.1 Test Period Adjusted for Known & Measurable Changes Total	Labor	Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $
1	Distribution Expenses									
2	Maintenance:									
3	Supervision and Engineering	885	62,659	59,432	3,227	(447)	(65)	62,147	58,985	3,162
4	Structures and Improvements	886	90	0	90	0	0	90	0	90
5	Mains	887	32,698	22,532	10,166	506	(10)	33,194	23,038	10,156
6	Compressor Station Equipment	888	0	0	0	0	0	0	0	0
7	Meas and Reg Station Exp-Gen	889	12,164	11,505	659	345	(12)	12,497	11,850	647
8	Meas and Reg Station Exp-Industrial	890	0	0	0	0	0	0	0	0
9	Meas and Reg Station Exp-City Gate	891	1,713	1,449	264	43	0	1,756	1,492	264
9	Services	892	40,195	30,251	9,944	908	12	41,115	31,159	9,956
10	Meters and House Regulators	893	87,490	76,385	11,105	(2,370)	(684)	84,436	74,015	10,421
11	Other Equipment	894	0	0	0	0	0	0	0	0
12										
13	Total Maintenance		237,009	201,554	35,455	(1,015)	(759)	235,235	200,539	34,696
14										
15	Customer Accounts Expenses									
16	Operations:									
17	Supervision	901	148,579	167,288	(18,709)	5,534	(56)	154,057	172,822	(18,765)
18	Meter Reading Expenses	902	252,793	223,298	29,495	6,699	0	259,492	229,997	29,495
19	Customer Records & Collections	903	424,220	283,658	140,562	8,755	616	433,591	292,413	141,178
20	Uncollectible Accounts	904	90,612	0	90,612	0	(2,018)	88,594	0	88,594
21	Misc. Customer Accounts Expense	905	15,433	14	15,419	0	0	15,433	14	15,419
22										
23	Total Customer Accounts Expenses		931,637	674,258	257,379	20,988	(1,458)	951,167	695,246	255,921
24										
25	Customer Service & Info. Expenses									
26	Operations:									
27	Supervision	907	6,937	6,937	0	229	0	7,166	7,166	0
28	Customer Assistance Expense	908	1,078,057	58,320	1,019,737	1,929	(312,899)	767,087	60,249	706,838
29	Information & Instruction Expense	909	23,202	13,259	9,943	438	30	23,670	13,697	9,973
30	Misc. Customer Service Expense	910	15,161	10,311	4,850	325	9	15,495	10,636	4,859
31										
32	Total Customer Accounts Expenses		1,123,357	88,827	1,034,530	2,921	(312,860)	813,418	91,748	721,670

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998

Line No.	Description	Account No.	Schedule No. 4.5 Base Period Twelve Months Ended December 31, 1998 Total	Labor	Other	Adjustments Labor	Other	Schedule No. 4.1 Test Period Adjusted for Known & Measurable Changes Total	Labor	Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $
1	Sales Expenses									
2	Operations:									
3	Supervision	911	0	0	0	0	0	0	0	0
4	Demonstrating and Selling	912	0	0	0	0	0	0	0	0
5	Advertising	913	(1,958)	(2,227)	269	2,227	(269)	0	0	0
6										
7	Total Customer Accounts Expenses		(1,958)	(2,227)	269	2,227	(269)	0	0	0
8										
9	Administrative and General Expenses									
10	Salaries	920	875,992	1,161,083	(285,091)	(115,712)	38,946	799,226	1,045,371	(246,145)
11	Office Supplies & Expense	921	579,649	18,416	561,233	(1,996)	(51,791)	525,862	16,420	509,442
12	A&G Expense Transferred	922	(821,220)	0	(821,220)	0	64,838	(756,382)	0	(756,382)
13	Outside Services	923	259,498	0	259,498	0	(31,032)	228,466	0	228,466
14	Workmens Comp Insurance	924	0	0	0	0	0	0	0	0
15	Property Insurance	924	24,362	0	24,362	0	(1,532)	22,830	0	22,830
16	Injuries and Damages	925	88,171	5,613	82,558	(196)	(5,193)	82,782	5,417	77,365
17	Pensions and Benefits	926	775,922	43,813	732,109	(4,850)	(100,012)	671,060	38,963	632,097
18	Regulatory Commission Expense	928	0	0	0	0	0	0	0	0
19	Miscellaneous General Expense	930	319,888	9,542	310,346	(889)	(132,093)	186,906	8,653	178,253
20	Rents	931	249,686	0	249,686	0	(13,315)	236,371	0	236,371
21	Building Maintenance	932	283,909	23,460	260,449	(1,229)	(30,216)	252,464	22,231	230,233
22										
23	Total Administrative & General		2,635,857	1,261,927	1,373,930	(124,872)	(261,400)	2,249,585	1,137,055	1,112,530
24										
25	Total Operations & Maintenance		6,324,871	3,243,507	3,081,364	(77,280)	(561,437)	5,686,154	3,166,227	2,519,927
26										
27	Labor Adjustment	3.00%		97,305						

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.3 South Dakota Direct Labor	Schedule No. 4.3 South Dakota Direct Other	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Labor	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$	$	$	$	$
1	Gas Production Expenses							
2	Operations:							
3	Supervision and Engineering	710	9,285	1,269	2,852	141	12,137	1,410
4	LP Gas Expense	717	421	37	0	0	421	37
5	Fuel	723	0	2,656	0	0	0	2,656
6	LP Gas	728	0	0	0	0	0	0
7	Miscellaneous	735	919	1,067	0	0	919	1,067
8								
9	Total Operations		10,625	5,029	2,852	141	13,477	5,170
10								
11	Maintenance:							
12	Supervision and Engineering	740	7,233	1,029	1,905	92	9,138	1,121
13	Structures	741	2,237	68	0	0	2,237	68
14	Production Equipment	742	0	1,411	0	0	0	1,411
15								
16	Total Maintenance		9,470	2,508	1,905	92	11,375	2,600
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	184,655	235,066	15,270	1,720	199,925	236,786
21	Load Dispatching	871	3,993	737	69,843	40,672	73,836	41,409
22	Compressor Station Expenses	872	0	0	0	0	0	0
23	Mains and Services Expenses	874	152,365	258,911	36	15,237	152,401	274,148
24	Meas and Reg Station Exp-Gen	875	13,311	2,595	0	0	13,311	2,595
25	Meas and Reg Station Exp-Industrial	876	0	0	0	0	0	0
26	Meas and Reg Station Exp-City Gate	877	35,369	8,509	0	0	35,369	8,509
27	Meter and House Regulator Expense	878	266,989	77,702	0	(86,603)	266,989	(8,901)
28	Customer Installation Expense	879	46,765	(8,906)	180	(197,079)	46,945	(205,985)
29	Other Expense	880	206,703	25,305	21,308	8,973	228,011	34,278
30	Rents	881	0	0	0	4,501	0	4,501
31								
32	Total Operations		910,150	599,919	106,637	(212,579)	1,016,787	387,340

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.3 South Dakota Direct Labor	Schedule No. 4.3 South Dakota Direct Other	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Labor	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$	$	$	$	$
1	Distribution Expenses							
2	Maintenance:							
3	Supervision and Engineering	885	28,313	2,268	30,672	894	58,985	3,162
4	Structures and Improvements	886	0	90	0	0	0	90
5	Mains	887	20,699	10,021	2,339	135	23,038	10,156
6	Compressor Station Equipment	888	0	0	0	0	0	0
7	Meas and Reg Station Exp-Gen	889	11,850	481	0	166	11,850	647
8	Meas and Reg Station Exp-Industrial	890	0	0	0	0	0	0
9	Meas and Reg Station Exp-City Gate	891	1,492	264	0	0	1,492	264
9	Services	892	31,159	10,117	0	(161)	31,159	9,956
10	Meters and House Regulators	893	9,917	1,028	64,098	9,393	74,015	10,421
11	Other Equipment	894	0	0	0	0	0	0
12								
13	Total Maintenance		103,430	24,269	97,109	10,427	200,539	34,696
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	0	0	172,822	(18,765)	172,822	(18,765)
18	Meter Reading Expenses	902	229,997	29,495	0	0	229,997	29,495
19	Customer Records & Collections	903	210,012	(65,591)	82,401	206,769	292,413	141,178
20	Uncollectible Accounts	904	0	71,312	0	17,282	0	88,594
21	Misc. Customer Accounts Expense	905	14	15,419	0	0	14	15,419
22								
23	Total Customer Accounts Expenses		440,023	50,635	255,223	205,286	695,246	255,921
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	0	0	7,166	0	7,166	0
28	Customer Assistance Expense	908	0	0	60,249	706,838	60,249	706,838
29	Information & Instruction Expense	909	0	0	13,697	9,973	13,697	9,973
30	Misc. Customer Service Expense	910	5,090	1,852	5,546	3,007	10,636	4,859
31								
32	Total Customer Accounts Expenses		5,090	1,852	86,658	719,818	91,748	721,670

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.3 South Dakota Direct Labor	Schedule No. 4.3 South Dakota Direct Other	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Labor	Schedule No. 4.2 Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Sales Expenses							
2	Operations:							
3	Supervision	911	0	0	0	0	0	0
4	Demonstrating and Selling	912	0	0	0	0	0	0
5	Advertising	913	0	0	0	0	0	0
6								
7	Total Customer Accounts Expenses		0	0	0	0	0	0
8								
9	Administrative and General Expenses							
10	Salaries	920	93,884	0	951,487	(246,145)	1,045,371	(246,145)
11	Office Supplies & Expense	921	318	182,115	16,102	327,327	16,420	509,442
12	A&G Expense Transferred	922	0	0	0	(756,382)	0	(756,382)
13	Outside Services	923	0	0	0	228,466	0	228,466
14	Workmens Comp Insurance	924	0	0	0	0	0	0
15	Property Insurance	924	0	0	0	22,830	0	22,830
16	Injuries and Damages	925	0	0	5,417	77,365	5,417	77,365
17	Pensions and Benefits	926	0	0	38,963	632,097	38,963	632,097
18	Regulatory Commission Expense	928	0	0	0	0	0	0
19	Miscellaneous General Expense	930	0	2,060	8,653	176,193	8,653	178,253
20	Rents	931	0	138,344	0	98,027	0	236,371
21	Building Maintenance	932	7,997	7,781	14,234	222,452	22,231	230,233
22								
23	Total Administrative & General		102,199	330,300	1,034,856	782,230	1,137,055	1,112,530
24								
25	Total Operations & Maintenance		1,580,987	1,014,512	1,585,240	1,505,415	3,166,227	2,519,927

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NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.4 Total Company Undistributed Expenses Labor	Other	Gas Factor	South Dakota Factor	Allocated to South Dakota Labor	Other
	(a)	(b)	(c) $	(d) $	(e)	(f)	(g) $	(h) $
1	Gas Production Expenses				Schedule No. 10			
2	Operations:							
3	Supervision and Engineering	710	5,186	257	1.0000	0.5500 E	2,852	141
4	LP Gas Expense	717	0	0	1.0000	0.5500 E	0	0
5	Fuel	723	0	0	1.0000	0.5500 E	0	0
6	LP Gas	728	0	0	1.0000	0.5500 E	0	0
7	Miscellaneous	735	0	0	1.0000	0.5500 E	0	0
8								
9	Total Operations		5,186	257			2,852	141
10								
11	Maintenance:							
12	Supervision and Engineering	740	3,463	168	1.0000	0.5500 E	1,905	92
13	Structures	741	0	0	1.0000	0.5500 E	0	0
14	Production Equipment	742	0	0	1.0000	0.5500 E	0	0
15								
16	Total Maintenance		3,463	168			1,905	92
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	27,763	3,127	1.0000	0.5500 E	15,270	1,720
21	Load Dispatching	871	126,987	73,949	1.0000	0.5500 E	69,843	40,672
22	Compressor Station Expenses	872	0	0	1.0000	0.5500 E	0	0
23	Mains and Services Expenses	874	66	27,703	1.0000	0.5500 E	36	15,237
24	Meas and Reg Station Exp-Gen	875	0	0	1.0000	0.5500 E	0	0
25	Meas and Reg Station Exp-Industrial	876	0	0	1.0000	0.5500 E	0	0
26	Meas and Reg Station Exp-City Gate	877	0	0	1.0000	0.5500 E	0	0
27	Meter and House Regulator Expense	878	0	(157,460)	1.0000	0.5500 E	0	(86,603)
28	Customer Installation Expense	879	328	(358,325)	1.0000	0.5500 E	180	(197,079)
29	Other Expense	880	38,742	16,315	1.0000	0.5500 E	21,308	8,973
30	Rents	881	0	8,184	1.0000	0.5500 E	0	4,501
31								
32	Total Operations		193,886	(386,507)			106,637	(212,579)

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.4 Total Company Undistributed Expenses Labor	Other	Gas Factor	South Dakota Factor	Allocated to South Dakota Labor	Other
	(a)	(b)	(c) $	(d) $	(e)	(f)	(g) $	(h) $
1	Distribution Expenses				Schedule No. 10			
2	Maintenance:							
3	Supervision and Engineering	885	55,767	1,626	1.0000	0.5500 E	30,672	894
4	Structures and Improvements	886	0	0	1.0000	0.5500 E	0	0
5	Mains	887	4,252	245	1.0000	0.5500 E	2,339	135
6	Compressor Station Equipment	888	0	0	1.0000	0.5500 E	0	0
7	Meas and Reg Station Exp-Gen	889	0	301	1.0000	0.5500 E	0	166
8	Meas and Reg Station Exp-Industrial	890	0	0	1.0000	0.5500 E	0	0
9	Meas and Reg Station Exp-City Gate	891	0	0	1.0000	0.5500 E	0	0
9	Services	892	0	(293)	1.0000	0.5500 E	0	(161)
10	Meters and House Regulators	893	116,541	17,079	1.0000	0.5500 E	64,098	9,393
11	Other Equipment	894	0	0	1.0000	0.5500 E	0	0
12								
13	Total Maintenance		176,560	18,958			97,109	10,427
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	596,164	(64,730)	0.5854 A	0.4952 A	172,822	(18,765)
18	Meter Reading Expenses	902	0	0	0.5854 A	0.4952 A	0	0
19	Customer Records & Collections	903	284,250	713,268	0.5854 A	0.4952 A	82,401	206,769
20	Uncollectible Accounts	904	0	78,057	0.4471 B	0.4952 A	0	17,282
21	Misc. Customer Accounts Expense	905	0	0	0.5854 A	0.4952 A	0	0
22								
23	Total Customer Accounts Expenses		880,414	726,595			255,223	205,286
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	24,721	0	0.5854 A	0.4952 A	7,166	0
28	Customer Assistance Expense	908	207,835	2,438,287	0.5854 A	0.4952 A	60,249	706,838
29	Information & Instruction Expense	909	47,249	34,401	0.5854 A	0.4952 A	13,697	9,973
30	Misc. Customer Service Expense	910	19,133	10,374	0.5854 A	0.4952 A	5,546	3,007
31								
32	Total Customer Accounts Expenses		298,938	2,483,072			86,658	719,818

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.4 Total Company Undistributed Expenses Labor	Other	Gas Factor	South Dakota Factor	Allocated to South Dakota Labor	Other
	(a)	(b)	(c) $	(d) $	(e)	(f)	(g) $	(h) $
1	Sales Expenses				Schedule No. 10			
2	Operations:							
3	Supervision	911	0	0	0.2257 G	0.4952 A	0	0
4	Demonstrating and Selling	912	0	0	0.2257 G	0.4952 A	0	0
5	Advertising	913	0	0	0.2257 G	0.4952 A	0	0
6								
7	Total Customer Accounts Expenses		0	0			0	0
8								
9	Administrative and General Expenses							
10	Salaries	920	4,335,779	(1,121,647)	0.3990 D	0.5500 E	951,487	(246,145)
11	Office Supplies & Expense	921	73,376	1,491,579	0.3990 D	0.5500 E	16,102	327,327
12	A&G Expense Transferred	922	0	(3,399,850)	0.4045 H	0.5500 E	0	(756,382)
13	Outside Services	923	0	1,221,742	0.3400 E	0.5500 E	0	228,466
14	Workmens Comp Insurance	924	0	0	0.3990 D	0.5500 E	0	0
15	Property Insurance	924	0	216,640	0.1916 F	0.5500 E	0	22,830
16	Injuries and Damages	925	51,409	734,149	0.1916 F	0.5500 E	5,417	77,365
17	Pensions and Benefits	926	177,548	2,880,367	0.3990 D	0.5500 E	38,963	632,097
18	Regulatory Commission Expense	928	0	0	0.1916 F	0.5500 E	0	0
19	Miscellaneous General Expense	930	46,271	942,211	0.3400 E	0.5500 E	8,653	176,193
20	Rents	931	0	524,207	0.3400 E	0.5500 E	0	98,027
21	Building Maintenance	932	76,115	1,189,585	0.3400 E	0.5500 E	14,234	222,452
22								
23	Total Administrative & General		4,760,498	4,678,983			1,034,856	782,230
24								
25	Total Operations & Maintenance		6,318,945	7,521,526			1,585,240	1,505,415

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Nebraska Direct Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.5 Base Period South Dakota Direct Labor	Schedule No. 4.5 Base Period South Dakota Direct Other	Adjustments Labor	Adjustments Other	Test Period South Dakota Direct Labor	Test Period South Dakota Direct Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Gas Production Expenses							
2	Operations:							
3	Supervision and Engineering	710	9,015	1,269	270	0	9,285	1,269
4	LP Gas Expense	717	409	37	12	0	421	37
5	Fuel	723	0	2,656	0	0	0	2,656
6	LP Gas	728	0	132	0	(132)	0	0
7	Miscellaneous	735	892	1,067	27	0	919	1,067
8								
9	Total Operations		10,316	5,161	309	(132)	10,625	5,029
10								
11	Maintenance:							
12	Supervision and Engineering	740	7,022	1,029	211	0	7,233	1,029
13	Structures	741	2,172	68	65	0	2,237	68
14	Production Equipment	742	0	1,411	0	0	0	1,411
15								
16	Total Maintenance		9,194	2,508	276	0	9,470	2,508
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	179,277	235,066	5,378	0	184,655	235,066
21	Load Dispatching	871	3,877	737	116	0	3,993	737
22	Compressor Station Expenses	872	0	0	0	0	0	0
23	Mains and Services Expenses	874	147,927	258,911	4,438	0	152,365	258,911
24	Meas and Reg Station Exp-Gen	875	12,923	2,595	388	0	13,311	2,595
25	Meas and Reg Station Exp-Industrial	876	0	0	0	0	0	0
26	Meas and Reg Station Exp-City Gate	877	34,339	8,509	1,030	0	35,369	8,509
27	Meter and House Regulator Expense	878	259,213	77,702	7,776	0	266,989	77,702
28	Customer Installation Expense	879	45,403	(8,906)	1,362	0	46,765	(8,906)
29	Other Expense	880	200,683	25,305	6,020	0	206,703	25,305
30	Rents	881	0	0	0	0	0	0
31								
32	Total Operations		883,642	599,919	26,508	0	910,150	599,919

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Nebraska Direct Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.5 Base Period South Dakota Direct Labor	Schedule No. 4.5 Base Period South Dakota Direct Other	Adjustments Labor	Adjustments Other	Test Period South Dakota Direct Labor	Test Period South Dakota Direct Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Distribution Expenses							
2	Maintenance:							
3	Supervision and Engineering	885	27,488	2,268	825	0	28,313	2,268
4	Structures and Improvements	886	0	90	0	0	0	90
5	Mains	887	20,096	10,021	603	0	20,699	10,021
6	Compressor Station Equipment	888	0	0	0	0	0	0
7	Meas and Reg Station Exp-Gen	889	11,505	481	345	0	11,850	481
8	Meas and Reg Station Exp-Industrial	890	0	0	0	0	0	0
9	Meas and Reg Station Exp-City Gate	891	1,449	264	43	0	1,492	264
9	Services	892	30,251	10,117	908	0	31,159	10,117
10	Meters and House Regulators	893	9,628	1,028	289	0	9,917	1,028
11	Other Equipment	894	0	0	0	0	0	0
12								
13	Total Maintenance		100,417	24,269	3,013	0	103,430	24,269
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	0	0	0	0	0	0
18	Meter Reading Expenses	902	223,298	29,495	6,699	0	229,997	29,495
19	Customer Records & Collections	903	203,895	(65,591)	6,117	0	210,012	(65,591)
20	Uncollectible Accounts	904	0	71,312	0	0	0	71,312
21	Misc. Customer Accounts Expense	905	14	15,419	0	0	14	15,419
22								
23	Total Customer Accounts Expenses		427,207	50,635	12,816	0	440,023	50,635
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	0	0	0	0	0	0
28	Customer Assistance Expense	908	0	0	0	0	0	0
29	Information & Instruction Expense	909	0	0	0	0	0	0
30	Misc. Customer Service Expense	910	4,942	1,852	148	0	5,090	1,852
31								
32	Total Customer Accounts Expenses		4,942	1,852	148	0	5,090	1,852

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Nebraska Direct Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.5 Base Period South Dakota Direct Labor	Schedule No. 4.5 Base Period South Dakota Direct Other	Adjustments Labor	Adjustments Other	Test Period South Dakota Direct Labor	Test Period South Dakota Direct Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Sales Expenses							
2	Operations:							
3	Supervision	911	0	0	0	0	0	0
4	Demonstrating and Selling	912	0	0	0	0	0	0
5	Advertising	913	0	0	0	0	0	0
6								
7	Total Customer Accounts Expenses		0	0	0	0	0	0
8								
9	Administrative and General Expenses							
10	Salaries	920	91,148	0	2,736	0	93,884	0
11	Office Supplies & Expense	921	309	182,115	9	0	318	182,115
12	A&G Expense Transferred	922	0	0	0	0	0	0
13	Outside Services	923	0	0	0	0	0	0
14	Workmens Comp Insurance	924	0	0	0	0	0	0
15	Property Insurance	924	0	0	0	0	0	0
16	Injuries and Damages	925	0	0	0	0	0	0
17	Pensions and Benefits	926	0	0	0	0	0	0
18	Regulatory Commission Expense	928	0	0	0	0	0	0
19	Miscellaneous General Expense	930	0	2,060	0	0	0	2,060
20	Rents	931	0	138,344	0	0	0	138,344
21	Building Maintenance	932	7,764	7,781	233	0	7,997	7,781
22								
23	Total Administrative & General		99,221	330,300	2,978	0	102,199	330,300
24								
25	Total Operations & Maintenance		1,534,939	1,014,644	46,048	(132)	1,580,987	1,014,512
26								
27	Labor Adjustment	3.00%			46,048			
28	Remove Promotional Advertising				0	0		
29	Remove Institutional Advertising				0	0		
30	Remove LP Gas				0	(132)		
31								
32	Total Adjustments				46,048	(132)		

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Schedule No. 4.4
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Line No.	Description	Account No.	Schedule No. 4.6 Base Period - Total Company Undistributed Expenses Labor	Schedule No. 4.6 Base Period - Total Company Undistributed Expenses Other	Adjustments Labor	Adjustments Other	Test Period Total Company Undistributed Expenses Labor	Test Period Total Company Undistributed Expenses Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Gas Production Expenses							
2	Operations:							
3	Supervision and Engineering	710	5,035	257	151	0	5,186	257
4	LP Gas Expense	717	0	0	0	0	0	0
5	Fuel	723	0	0	0	0	0	0
6	LP Gas	728	0	0	0	0	0	0
7	Miscellaneous	735	0	0	0	0	0	0
8								
9	Total Operations		5,035	257	151	0	5,186	257
10								
11	Maintenance:							
12	Supervision and Engineering	740	3,362	168	101	0	3,463	168
13	Structures	741	0	0	0	0	0	0
14	Production Equipment	742	0	0	0	0	0	0
15								
16	Total Maintenance		3,362	168	101	0	3,463	168
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	26,954	3,127	809	0	27,763	3,127
21	Load Dispatching	871	123,288	73,949	3,699	0	126,987	73,949
22	Compressor Station Expenses	872	0	0	0	0	0	0
23	Mains and Services Expenses	874	64	27,703	2	0	66	27,703
24	Meas and Reg Station Exp-Gen	875	0	0	0	0	0	0
25	Meas and Reg Station Exp-Industrial	876	0	0	0	0	0	0
26	Meas and Reg Station Exp-City Gate	877	0	0	0	0	0	0
27	Meter and House Regulator Expense	878	0	(157,460)	0	0	0	(157,460)
28	Customer Installation Expense	879	318	(358,325)	10	0	328	(358,325)
29	Other Expense	880	37,614	16,315	1,128	0	38,742	16,315
30	Rents	881	0	8,184	0	0	0	8,184
31								
32	Total Operations		188,238	(386,507)	5,648	0	193,886	(386,507)

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NorthWestern Public Service
Operations and Maintenance Expenses by Account - Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.6 Base Period - Total Company Undistributed Expenses Labor	Schedule No. 4.6 Base Period - Total Company Undistributed Expenses Other	Adjustments Labor	Adjustments Other	Test Period Total Company Undistributed Expenses Labor	Test Period Total Company Undistributed Expenses Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Distribution Expenses							
2	Maintenance:							
3	Supervision and Engineering	885	54,143	1,626	1,624	0	55,767	1,626
4	Structures and Improvements	886	0	0	0	0	0	0
5	Mains	887	4,128	245	124	0	4,252	245
6	Compressor Station Equipment	888	0	0	0	0	0	0
7	Meas and Reg Station Exp-Gen	889	0	301	0	0	0	301
8	Meas and Reg Station Exp-Industrial	890	0	0	0	0	0	0
9	Meas and Reg Station Exp-City Gate	891	0	0	0	0	0	0
9	Services	892	0	(293)	0	0	0	(293)
10	Meters and House Regulators	893	113,147	17,079	3,394	0	116,541	17,079
11	Other Equipment	894	0	0	0	0	0	0
12								
13	Total Maintenance		171,418	18,958	5,142	0	176,560	18,958
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	578,800	(64,730)	17,364	0	596,164	(64,730)
18	Meter Reading Expenses	902	0	0	0	0	0	0
19	Customer Records & Collections	903	275,971	713,268	8,279	0	284,250	713,268
20	Uncollectible Accounts	904	0	78,057	0	0	0	78,057
21	Misc. Customer Accounts Expense	905	0	0	0	0	0	0
22								
23	Total Customer Accounts Expenses		854,771	726,595	25,643	0	880,414	726,595
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	24,001	0	720	0	24,721	0
28	Customer Assistance Expense	908	201,782	3,528,181	6,053	(1,089,884)	207,835	2,438,297
29	Information & Instruction Expense	909	45,873	34,401	1,376	0	47,249	34,401
30	Misc. Customer Service Expense	910	18,576	10,374	557	0	19,133	10,374
31								
32	Total Customer Accounts Expenses		290,232	3,572,956	8,706	(1,089,884)	298,938	2,483,072

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Test Period Details

Line No.	Description	Account No.	Schedule No. 4.8 Base Period - Total Company Undistributed Expenses Labor	Schedule No. 4.8 Base Period - Total Company Undistributed Expenses Other	Adjustments Labor	Adjustments Other	Test Period Total Company Undistributed Expenses Labor	Test Period Total Company Undistributed Expenses Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Sales Expenses							
2	Operations:							
3	Supervision	911	0	0	0	0	0	0
4	Demonstrating and Selling	912	0	0	0	0	0	0
5	Advertising	913	(17,911)	2,165	17,911	(2,165)	0	0
6								
7	Total Customer Accounts Expenses		(17,911)	2,165	17,911	(2,165)	0	0
8								
9	Administrative and General Expenses							
10	Salaries	920	4,209,493	(1,121,647)	126,286	0	4,335,779	(1,121,647)
11	Office Supplies & Expense	921	71,239	1,491,579	2,137	0	73,376	1,491,579
12	A&G Expense Transferred	922	0	(3,399,850)	0	0	0	(3,399,850)
13	Outside Services	923	0	1,221,742	0	0	0	1,221,742
14	Workmens Comp Insurance	924	0	0	0	0	0	0
15	Property Insurance	924	0	216,640	0	0	0	216,640
16	Injuries and Damages	925	49,912	734,149	1,497	0	51,409	734,149
17	Pensions and Benefits	926	172,377	2,880,367	5,171	0	177,548	2,880,367
18	Regulatory Commission Expense	928	0	0	0	0	0	0
19	Miscellaneous General Expense	930	44,923	1,451,439	1,348	(509,228)	46,271	942,211
20	Rents	931	0	524,207	0	0	0	524,207
21	Building Maintenance	932	73,898	1,189,585	2,217	0	76,115	1,189,585
22								
23	Total Administrative & General		4,621,842	5,188,211	138,656	(509,228)	4,760,498	4,678,983
24								
25	Total Operations & Maintenance		6,116,987	9,122,803	201,958	(1,601,277)	6,318,945	7,521,526
26								
27	Labor Adjustment	3.00%			183,510	0		
28	Remove Promotional Advertising				18,448	(2,165)		
29	Remove Institutional Advertising				0	(509,228)		
30	Adjust Affiliate Management Fees				0	(1,089,884)		
31								
32	Total Adjustments				201,958	(1,601,277)		

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Base Period Details

Schedule No. 4.6

Line No.	Description	Account No.	South Dakota Direct Labor	South Dakota Direct Other	Undistributed Company Allocated to South Dakota Labor	Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Gas Production Expenses							
2	Operations:							
3	Supervision and Engineering	710	9,015	1,269	2,971	152	11,986	1,421
4	LP Gas Expense	717	409	37	0	0	409	37
5	Fuel	723	0	2,656	0	0	0	2,656
6	LP Gas	728	0	132	0	0	0	132
7	Miscellaneous	735	892	1,067	0	0	892	1,067
8								
9	Total Operations		10,316	5,161	2,971	152	13,287	5,313
10								
11	Maintenance:							
12	Supervision and Engineering	740	7,022	1,029	1,984	99	9,006	1,128
13	Structures	741	2,172	68	0	0	2,172	68
14	Production Equipment	742	0	1,411	0	0	0	1,411
15								
16	Total Maintenance		9,194	2,508	1,984	99	11,178	2,607
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	179,277	235,066	15,903	1,845	195,180	236,911
21	Load Dispatching	871	3,877	737	72,740	43,630	76,617	44,367
22	Compressor Station Expenses	872	0	0	0	0	0	0
23	Mains and Services Expenses	874	147,927	258,911	38	16,345	147,965	275,256
24	Meas and Reg Station Exp-Gen	875	12,923	2,595	0	0	12,923	2,595
25	Meas and Reg Station Exp-Industrial	876	0	0	0	0	0	0
26	Meas and Reg Station Exp-City Gate	877	34,339	8,509	0	0	34,339	8,509
27	Meter and House Regulator Expense	878	259,213	77,702	0	(92,901)	259,213	(15,199)
28	Customer Installation Expense	879	45,403	(8,906)	188	(211,412)	45,591	(220,318)
29	Other Expense	880	200,683	25,305	22,192	9,626	222,875	34,931
30	Rents	881	0	0	0	4,829	0	4,829
31								
32	Total Operations		883,642	599,919	111,061	(228,038)	994,703	371,881

NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Base Period Details

Line No.	Description	Account No.	Schedule No. 4.6 South Dakota Direct Labor	South Dakota Direct Other	Undistributed Company Allocated to South Dakota Labor	Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Distribution Expenses							
2	Maintenance:							
3	Supervision and Engineering	885	27,488	2,268	31,944	959	59,432	3,227
4	Structures and Improvements	886	0	90	0	0	0	90
5	Mains	887	20,096	10,021	2,436	145	22,532	10,166
6	Compressor Station Equipment	888	0	0	0	0	0	0
7	Meas and Reg Station Exp-Gen	889	11,505	481	0	178	11,505	659
8	Meas and Reg Station Exp-Industrial	890	0	0	0	0	0	0
9	Meas and Reg Station Exp-City Gate	891	1,449	264	0	0	1,449	264
9	Services	892	30,251	10,117	0	(173)	30,251	9,944
10	Meters and House Regulators	893	9,628	1,028	66,757	10,077	76,385	11,105
11	Other Equipment	894	0	0	0	0	0	0
12								
13	Total Maintenance		100,417	24,269	101,137	11,186	201,554	35,455
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	0	0	167,288	(18,709)	167,288	(18,709)
18	Meter Reading Expenses	902	223,298	29,495	0	0	223,298	29,495
19	Customer Records & Collections	903	203,895	(65,591)	79,763	206,153	283,658	140,562
20	Uncollectible Accounts	904	0	71,312	0	19,300	0	90,612
21	Misc. Customer Accounts Expense	905	14	15,419	0	0	14	15,419
22								
23	Total Customer Accounts Expenses		427,207	50,635	247,051	206,744	674,258	257,379
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	0	0	6,937	0	6,937	0
28	Customer Assistance Expense	908	0	0	58,320	1,019,737	58,320	1,019,737
29	Information & Instruction Expense	909	0	0	13,259	9,943	13,259	9,943
30	Misc. Customer Service Expense	910	4,942	1,852	5,369	2,998	10,311	4,850
31								
32	Total Customer Accounts Expenses		4,942	1,852	83,885	1,032,678	88,827	1,034,530

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NorthWestern Public Service
Operations and Maintenance Expenses by Account
Twelve Months Ending December 31, 1998 - Base Period Details

Line No.	Description	Account No.	South Dakota Direct Labor	South Dakota Direct Other	Schedule No. 4.6 Undistributed Company Allocated to South Dakota Labor	Schedule No. 4.6 Undistributed Company Allocated to South Dakota Other	South Dakota Total Labor	South Dakota Total Other
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Sales Expenses							
2	Operations:							
3	Supervision	911	0	0	0	0	0	0
4	Demonstrating and Selling	912	0	0	0	0	0	0
5	Advertising	913	0	0	(2,227)	269	(2,227)	269
6								
7	Total Customer Accounts Expenses		0	0	(2,227)	269	(2,227)	269
8								
9	Administrative and General Expenses							
10	Salaries	920	91,148	0	1,069,935	(285,091)	1,161,083	(285,091)
11	Office Supplies & Expense	921	309	182,115	18,107	379,118	18,416	561,233
12	A&G Expense Transferred	922	0	0	0	(821,220)	0	(821,220)
13	Outside Services	923	0	0	0	259,498	0	259,498
14	Workmens Comp Insurance	924	0	0	0	0	0	0
15	Property Insurance	924	0	0	0	24,362	0	24,362
16	Injuries and Damages	925	0	0	5,613	82,558	5,613	82,558
17	Pensions and Benefits	926	0	0	43,813	732,109	43,813	732,109
18	Regulatory Commission Expense	928	0	0	0	0	0	0
19	Miscellaneous General Expense	930	0	2,060	9,542	308,286	9,542	310,346
20	Rents	931	0	138,344	0	111,342	0	249,686
21	Building Maintenance	932	7,764	7,781	15,696	252,668	23,460	260,449
22								
23	Total Administrative & General		99,221	330,300	1,162,706	1,043,630	1,261,927	1,373,930
24								
25	Total Operations & Maintenance		1,534,939	1,014,644	1,708,568	2,066,720	3,243,507	3,081,364

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Base Period Details

Line No.	Description	Account No.	Total Company Undistributed Expenses Labor	Total Company Undistributed Expenses Other	Gas Factor	S. Dakota Factor	Allocated to South Dakota Labor	Allocated to South Dakota Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$			$	$
1	Gas Production Expenses				Schedule No. 11			
2	Operations:							
3	Supervision and Engineering	710	5,035	257	1.0000	0.5900 E	2,971	152
4	LP Gas Expense	717	0	0	1.0000	0.5900 E	0	0
5	Fuel	723	0	0	1.0000	0.5900 E	0	0
6	LP Gas	728	0	0	1.0000	0.5900 E	0	0
7	Miscellaneous	735	0	0	1.0000	0.5900 E	0	0
8								
9	Total Operations		5,035	257			2,971	152
10								
11	Maintenance:							
12	Supervision and Engineering	740	3,362	168	1.0000	0.5900 E	1,984	99
13	Structures	741	0	0	1.0000	0.5900 E	0	0
14	Production Equipment	742	0	0	1.0000	0.5900 E	0	0
15								
16	Total Maintenance		3,362	168			1,984	99
17								
18	Distribution Expenses							
19	Operations:							
20	Supervision and Engineering	870	26,954	3,127	1.0000	0.5900 E	15,903	1,845
21	Load Dispatching	871	123,288	73,949	1.0000	0.5900 E	72,740	43,630
22	Compressor Station Expenses	872	0	0	1.0000	0.5900 E	0	0
23	Mains and Services Expenses	874	64	27,703	1.0000	0.5900 E	38	16,345
24	Meas and Reg Station Exp-Gen	875	0	0	1.0000	0.5900 E	0	0
25	Meas and Reg Station Exp-Industrial	876	0	0	1.0000	0.5900 E	0	0
26	Meas and Reg Station Exp-City Gate	877	0	0	1.0000	0.5900 E	0	0
27	Meter and House Regulator Expense	878	0	(157,460)	1.0000	0.5900 E	0	(92,901)
28	Customer Installation Expense	879	318	(358,325)	1.0000	0.5900 E	188	(211,412)
29	Other Expense	880	37,614	16,315	1.0000	0.5900 E	22,192	9,626
30	Rents	881	0	8,184	1.0000	0.5900 E	0	4,829
31								
32	Total Operations		188,238	(386,507)			111,061	(228,038)

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Base Period Details

Line No.	Description	Account No.	Total Company Undistributed Expenses Labor	Total Company Undistributed Expenses Other	Gas Factor	S. Dakota Factor	Allocated to South Dakota Labor	Allocated to South Dakota Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$			$	$
1	Distribution Expenses				Schedule No. 11			
2	Maintenance:							
3	Supervision and Engineering	885	54,143	1,626	1.0000	0.5900 E	31,944	959
4	Structures and Improvements	886	0	0	1.0000	0.5900 E	0	0
5	Mains	887	4,128	245	1.0000	0.5900 E	2,436	145
6	Compressor Station Equipment	888	0	0	1.0000	0.5900 E	0	0
7	Meas and Reg Station Exp-Gen	889	0	301	1.0000	0.5900 E	0	178
8	Meas and Reg Station Exp-Industrial	890	0	0	1.0000	0.5900 E	0	0
9	Meas and Reg Station Exp-City Gate	891	0	0	1.0000	0.5900 E	0	0
9	Services	892	0	(293)	1.0000	0.5900 E	0	(173)
10	Meters and House Regulators	893	113,147	17,079	1.0000	0.5900 E	66,757	10,077
11	Other Equipment	894	0	0	1.0000	0.5900 E	0	0
12								
13	Total Maintenance		171,418	18,958			101,137	11,186
14								
15	Customer Accounts Expenses							
16	Operations:							
17	Supervision	901	578,800	(64,730)	0.5846 A	0.4944 A	167,288	(18,709)
18	Meter Reading Expenses	902	0	0	0.5846 A	0.4944 A	0	0
19	Customer Records & Collections	903	275,971	713,268	0.5846 A	0.4944 A	79,763	206,153
20	Uncollectible Accounts	904	0	78,057	0.5001 B	0.4944 A	0	19,300
21	Misc. Customer Accounts Expense	905	0	0	0.5846 A	0.4944 A	0	0
22								
23	Total Customer Accounts Expenses		854,771	726,595			247,051	206,744
24								
25	Customer Service & Info. Expenses							
26	Operations:							
27	Supervision	907	24,001	0	0.5846 A	0.4944 A	6,937	0
28	Customer Assistance Expense	908	201,782	3,528,181	0.5846 A	0.4944 A	58,320	1,019,737
29	Information & Instruction Expense	909	45,873	34,401	0.5846 A	0.4944 A	13,259	9,943
30	Misc. Customer Service Expense	910	18,576	10,374	0.5846 A	0.4944 A	5,369	2,998
31								
32	Total Customer Accounts Expenses		290,232	3,572,956			83,885	1,032,678

NorthWestern Public Service
Operations and Maintenance Expenses by Account - Allocation of Undistributed Company Expenses
Twelve Months Ending December 31, 1998 - Base Period Details

Line No.	Description	Account No.	Total Company Undistributed Expenses Labor	Total Company Undistributed Expenses Other	Gas Factor	S. Dakota Factor	Allocated to South Dakota Labor	Allocated to South Dakota Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$			$	$
1	Sales Expenses				Schedule No. 11			
2	Operations:							
3	Supervision	911	0	0	0.2515 G	0.4944 A	0	0
4	Demonstrating and Selling	912	0	0	0.2515 G	0.4944 A	0	0
5	Advertising	913	(17,911)	2,165	0.2515 G	0.4944 A	(2,227)	269
6								
7	Total Customer Accounts Expenses		(17,911)	2,165			(2,227)	269
8								
9	Administrative and General Expenses							
10	Salaries	920	4,209,493	(1,121,647)	0.4308 D	0.5900 E	1,069,935	(285,091)
11	Office Supplies & Expense	921	71,239	1,491,579	0.4308 D	0.5900 E	18,107	379,118
12	A&G Expense Transferred	922	0	(3,399,850)	0.4094 H	0.5900 E	0	(821,220)
13	Outside Services	923	0	1,221,742	0.3600 E	0.5900 E	0	259,498
14	Workmens Comp Insurance	924	0	0	0.4308 D	0.5900 E	0	0
15	Property Insurance	924	0	216,640	0.1906 F	0.5900 E	0	24,362
16	Injuries and Damages	925	49,912	734,149	0.1906 F	0.5900 E	5,613	82,558
17	Pensions and Benefits	926	172,377	2,880,367	0.4308 D	0.5900 E	43,813	732,109
18	Regulatory Commission Expense	928	0	0	0.1906 F	0.5900 E	0	0
19	Miscellaneous General Expense	930	44,923	1,451,439	0.3600 E	0.5900 E	9,542	308,286
20	Rents	931	0	524,207	0.3600 E	0.5900 E	0	111,342
21	Building Maintenance	932	73,098	1,189,585	0.3600 E	0.5900 E	15,696	252,668
22								
23	Total Administrative & General		4,621,842	5,188,211			1,162,706	1,043,630
24								
25	Total Operations & Maintenance		6,116,987	9,122,803			1,708,568	2,066,720

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NorthWestern Public Service
Depreciation and Amortization Expense
Twelve Months Ending December 31, 1998

Schedule No. 5
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Line No.	Description / Functional Classification	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1			Schedule No. 11			Schedule No. 10			
2									
3	Direct South Dakota - Production	39,924	1.0000	1.0000	39,924	1.0000	1.0000	39,924	0
4									
5	Direct South Dakota - Transmission	0	1.0000	1.0000	0	1.0000	1.0000	0	0
6									
7	Direct South Dakota - Distribution	1,192,521	1.0000	1.0000	1,192,521	1.0000	1.0000	1,192,521	0
8									
9	General - Direct South Dakota	120,495	1.0000	1.0000	120,495	1.0000	1.0000	120,495	0
10									
11	General - Common	1,695,863	0.3600 E	0.5900 E	360,201	0.3400 E	0.5500 E	317,126	(43,075)
12									
13	Total	3,048,803			1,713,141			1,670,066	(43,075)
14									
15	Less Depreciation Charged to								
16	Transportation Clearing:								
17									
18	Direct South Dakota	47,718	1.0000	1.0000	47,718	1.0000	1.0000	47,718	0
19	Common	31,875	0.3600 E	0.5900 E	6,770	0.3400 E	0.5500 E	5,961	(809)
20									
21	Total Depreciation Expense	2,969,210			1,658,653			1,616,387	(42,266)
22									
23	Amortization of Limited Term Invest.	403	1.0000	1.0000	403	1.0000	1.0000	403	0
24									
25	Total Depr. and Amortization Expense	2,969,613			1,659,056			1,616,790	(42,266)

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NorthWestern Public Service
Taxes Other Than Income Taxes
Twelve Months Ending December 31, 1998

Line No.	Description	Actual Base Period	Adjustments	Test Period		Total Company	Gas Factor	South Dakota Factor	Allocated to South Dakota
	(a)	(b)	(c)	(d)		(e)	(f)	(g)	(h)
		$	$	$		$			$
						Base Period Factors - Schedule No. 11			
1	Delaware Franchise	12,415	132	12,547		102,000	0.1906 F	0.6386 F	12,415
2	South Dakota Gross Revenue	44,707	8,941	53,648	0.1500%	44,707	1.0000	1.0000	44,707
3	Federal Highway Use	811	(97)	714		3,816	0.3600 E	0.5900 E	811
4	Workers Comp Self-Insured	404	(27)	377		2,000	0.3600 E	0.5613 I	404
5	South Dakota Property Tax	617,333	292,400	909,733		617,333	1.0000	1.0000	617,333
6									
7	Total Expense	675,670	301,349	977,019		769,856			675,670
8									
9									
10						Test Period Adjustments			
11						0	0.0010	0.0034	132
12						8,941	0.0000	0.0000	8,941
13						0	(0.0200)	(0.0400)	(97)
14						0	(0.0200)	(0.0073)	(27)
15						292,400	0.0000	0.0000	292,400
16									
17						301,341			301,349
18									
19									
20						Test Period Factors - Schedule No. 10			
21						102,000	0.1916 F	0.6420 F	12,547
22						53,648	1.0000	1.0000	53,648
23						3,816	0.3400 E	0.5500 E	714
24						2,000	0.3400 E	0.5540 I	377
25					Sch 2, P1&3	909,733	1.0000	1.0000	909,733
26									
27						1,071,197			977,019

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NorthWestern Public Service
Computation of Federal and State Income Taxes
Twelve Months Ending December 31, 1998

Schedule No. 7
Page 1 of 1

Line No.	Description	Reference	Base Period Not Normalized	Base Period Normalizing Adjustments	Base Period Normalized	Adjustments to Reflect Requested Return	Test Period Total	Customer Charge Requirement Sch 12, P4
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
1	Return on Rate Base	Sch 9, L31	1,106,246	948,340	2,054,586	1,373,455	3,428,041	1,341,069
2								
3	Tax Adjustments:							
4	Interest Expense	Line 30	(1,203,230)	26,558	(1,176,672)	0	(1,176,672)	(460,321)
5								
6	Return Less Adjustments		(96,984)	974,898	877,914	1,373,455	2,251,369	880,748
7	Income Tax Gross-up Factor (1/.65)		1.538462	1.538462	1.538462	1.538462	1.538462	1.538462
8								
9	State Taxable Income		(149,206)	1,499,843	1,350,637	2,113,008	3,463,645	1,354,997
10	State Income Taxes		0	0	0	0	0	0
11								
12	Federal Taxable Income		(149,206)	1,499,843	1,350,637	2,113,008	3,463,645	1,354,997
13								
14	Income Tax Rates - %							
15	Federal Income Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
16	State Income Tax Rate		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17								
18	Income Tax Amounts - $							
19	Federal Income Taxes		(52,222)	524,945	472,723	739,553	1,212,276	474,249
20	State Income Taxes		0	0	0	0	0	0
21								
22	Total Income Taxes		(52,222)	524,945	472,723	739,553	1,212,276	474,249
23								
24								
25	Computation of Interest Expense							
26								
27	Net Rate Base	Sch 9, L28	37,808,884	(834,525)	36,974,359	0	36,974,359	14,464,581
28	Interest Component of Cost of Capital	Sch 9.2, L1	3.1824%	3.1824%	3.1824%	3.1824%	3.1824%	3.1824%
29								
30	Interest Expense		1,203,230	(26,558)	1,176,672	0	1,176,672	460,321

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NorthWestern Public Service
Computation of Rate Case Expenses
Twelve Months Ending December 31, 1998

Schedule No. 8
Page 1 of 1

Line No.	Description	Actual Base Period	Adjustments	Test Period
	(a)	(b)	(c)	(d)
		$	$	$
1	Past Rate Case Expense			
2	Yet Unamortized	0	0	0
3				
4	Consultant and Other Outside Expense	0	50,000	50,000
5				
6	SDPUC Rate Case Fund	0	100,000	100,000
7				
8	Total Rate Case Expense	0	150,000	150,000
9				
10	Three Year Amortization	0	50,000	50,000
11				
12				
13	Adjustment to Rate Base			
14				
15	Total Cost	0	150,000	150,000
16				
17	Less: 1/2 Year Amortization	0	25,000	25,000
18				
19	Net Adjustment to Rate Base	0	125,000	125,000

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NorthWestern Public Service
Computation of Rate Base and Return
Twelve Months Ending December 31, 1998

Line No.	Description	Reference	Base Period Not Normalized	Base Period Normalizing Adjustments	Base Period Normalized	Adjustments to Reflect Requested Return	Test Period Total
	(a)	(b)	(c) $	(d) $	(e) $	(f) $	(g) $
1	Plant in Service						
2	Direct South Dakota Gas Plant	Sch 9.1, L44	41,073,199	0	41,073,199	0	41,073,199
3	Common Plant	Sch 9.1, L47	9,029,339	(1,079,779)	7,949,560	0	7,949,560
4							
5	Subtotal		50,102,538	(1,079,779)	49,022,759	0	49,022,759
6							
7	Distribution Replacements						
8	Distribution Mains	Acct No. 376	0	0	0	0	0
9	Distribution Services	Acct No. 380	0	0	0	0	0
10	Construction in Service,						
11	Not Transferred						
12	Direct South Dakota Gas Plant	Sch 9.1, L51	1,854,584	0	1,854,584	0	1,854,584
13	Common Plant	Sch 9.1, L52	183,843	(21,985)	161,858	0	161,858
14							
15	Total Plant and Property		52,140,965	(1,101,764)	51,039,201	0	51,039,201
16							
17	Accumulated Depreciation & Amort.						
18	Direct South Dakota Gas Plant	Sch 9.4	14,215,894	0	14,215,894	0	14,215,894
19	Common Plant	Sch 9.3, P1	1,217,006	(145,536)	1,071,470	0	1,071,470
20							
21	Total Reserve		15,432,900	(145,536)	15,287,364	0	15,287,364
22							
23	Net Utility Plant		36,708,065	(956,228)	35,751,837	0	35,751,837
24	Working Capital	Sch 9.3, P3-5	1,720,172	0	1,720,172	0	1,720,172
25	Unamortized Rate Case Expense	Sch 8	0	125,000	125,000	0	125,000
26	Deferred Tax Reserve	Sch 9.3, P3-4	(619,353)	(3,297)	(622,650)	0	(622,650)
27							
28	Net Rate Base		37,808,884	(834,525)	36,974,359	0	36,974,359
29	Rate of Return - %		2.93%	2.63%	5.56%	3.71%	9.27%
30							
31	Return on Rate Base - $	Sch 1, L19	1,106,246	948,340	2,054,586	1,373,455	3,428,041

NorthWestern Public Service
Book Balances of Plant Accounts
December 31, 1997 and 1998

Line No.	Description	Reference	Per Books @ 12/31/97 Depreciable	Per Books @ 12/31/97 Non-Depreciable	Per Books @ 12/31/97 Total	Per Books @ 12/31/98 Depreciable	Per Books @ 12/31/98 Non-Depreciable	Per Books @ 12/31/98 Total	Base Year Thirteen Month Average	Test Year Thirteen Month Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			$	$	$	$	$	$	$	$
1	PRODUCTION-SOUTH DAKOTA									
2	304.0-Land and Land Rights		0	71,236	71,236	0	40,057	40,057	49,650	49,650
3	305.0-Structures and Improvements		263,049	0	263,049	263,049	0	263,049	263,049	263,049
4	311.0-Liquified Petroleum Gas Equip.		1,495,716	0	1,495,716	1,495,716	0	1,495,716	1,495,716	1,495,716
5	320.0-Other Equipment		11,567	0	11,567	11,567	0	11,567	11,567	11,567
6										
7	Total Production Plant		1,770,332	71,236	1,841,568	1,770,332	40,057	1,810,389	1,819,982	1,819,982
8										
9	DISTRIBUTION-SOUTH DAKOTA									
10	374.0-Land and Land Rights		(8,262)	199,153	190,891	0	207,454	207,454	201,417	201,417
11	375.0-Structures and Improvements		62,095	0	62,095	62,095	0	62,095	62,095	62,095
12	376.0-Mains		18,634,902	0	18,634,902	19,782,141	0	19,782,141	19,417,937	19,417,937
13	378.0-Meas. & Reg. Sta. Equip. - Gen.		438,357	0	438,357	580,270	0	580,270	497,796	497,796
14	379.0-Meas. & Reg. Sta. Equip. - City		605,490	0	605,490	842,241	0	842,241	760,336	760,336
15	380.0-Services		8,142,318	0	8,142,318	8,693,116	0	8,693,116	8,525,293	8,525,293
16	381.0-Meters		3,656,607	0	3,656,607	4,064,229	0	4,064,229	3,912,117	3,912,117
17	382.0-Meter Installations		1,280,458	0	1,280,458	1,537,674	0	1,537,674	1,437,108	1,437,108
18	383.0-Regulators		788,766	0	788,766	810,925	0	810,925	807,726	807,726
19	384.0-Regulator Installations		509,635	0	509,635	524,401	0	524,401	523,873	523,873
20										
21	Total Distribution Plant		34,110,366	199,153	34,309,519	36,897,092	207,454	37,104,546	36,145,698	36,145,698
22										
23	GENERAL-SOUTH DAKOTA									
24	303.0-Misc. Intangible Plant		2,931	0	2,931	7,327	0	7,327	4,960	4,960
25	389.0-Land and Land Rights		0	42,184	42,184	0	42,634	42,634	42,599	42,599
26	390.0-Structures and Improvements		344,713	0	344,713	372,559	0	372,559	362,163	362,163
27	391.0-Office Furniture & Equipment		39,603	0	39,603	40,949	0	40,949	40,333	40,333
28	392.0-Transportation Equipment		0	1,029,730	1,029,730	0	919,523	919,523	931,275	931,275
29	393.0-Stores Equipment		7,609	0	7,609	7,609	0	7,609	7,609	7,609
30	394.0-Tools, Shop and Garage Equip.		436,565	0	436,565	456,136	0	456,136	448,251	448,251
31	395.0-Laboratory Equipment		225,952	0	225,952	228,834	0	228,834	227,947	227,947
32	396.0-Power Operated Equipment		673,146	0	673,146	674,156	0	674,156	673,923	673,923
33	397.0-Communication Equipment		82,444	0	82,444	44,615	0	44,615	80,635	80,635
34	398.0-Miscellaneous Equipment		1,214	0	1,214	1,214	0	1,214	1,214	1,214
35										
36	*Total General Plant*		1,814,177	1,071,914	2,886,091	1,833,399	962,157	2,795,556	2,820,909	2,820,909
37										
38	Total Account 101 Plant - S. Dakota		37,694,875	1,342,303	39,037,178	40,500,823	1,209,668	41,710,491	40,786,589	40,786,589

NorthWestern Public Service
Book Balances of Plant Accounts
December 31, 1997 and 1998

Line No.	Description	Reference	Per Books @ 12/31/97 Depreciable	Per Books @ 12/31/97 Non-Depreciable	Per Books @ 12/31/97 Total	Per Books @ 12/31/98 Depreciable	Per Books @ 12/31/98 Non-Depreciable	Per Books @ 12/31/98 Total	Base Year Thirteen Month Average	Test Year Thirteen Month Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			$	$	$	$	$	$	$	$
39	GAS PLANT IN SERVICE									
40	Total Account 101 Plant - S. Dakota		37,694,875	1,342,303	39,037,178	40,500,823	1,209,668	41,710,491	40,786,589	40,786,589
41	COMPLETED NOT CLASSIFIED									
42	Total Account 106 Plant - S. Dakota		745,186	0	745,186	0	0	0	286,610	286,610
43										
44	TOTAL GAS PLANT - S. DAKOTA		38,440,061	1,342,303	39,782,364	40,500,823	1,209,668	41,710,491	41,073,199	41,073,199
45										
46	COMMON PLANT IN SERVICE									
47	Account 389-398 - S. Dakota Share	Sch 9.3, P1			9,189,350			8,599,529	9,029,339	7,949,560
48										
49	CONSTRUCTION IN SERVICE,									
50	NOT TRANSFERRED									
51	Direct South Dakota Gas Plant	Sch 9.3, P2			1,237,701			3,941,589	1,854,584	1,854,584
52	Common Plant - S. Dakota Share	Sch 9.3, P2			81,339			553,174	183,843	161,858
53										
54	Total Account 106 Plant - Common				1,319,040			4,494,763	2,038,427	2,016,442
55										
56	TOTAL PLANT AND PROPERTY				50,290,754			54,804,783	52,140,965	51,039,201

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NorthWestern Public Service
Consolidated Cost of Capital - NorthWestern Corporation
December 31, 1997 and 1998

Schedule No. 9.2
Page 1 of 1

Line No.	Description	Reference	Beginning of Period Capital Amounts	End of Period Amounts			Annual Interest or Dividend	Weighted Cost of Capital
				Capital Amounts	Ratios	Cost of Capital		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			$	$	%	%	$	%
1	Long-Term Debt	Line 27	425,281,000	588,875,000	43.5904%	7.3006%		3.1824%
2								
3	Preferred Stock Equity & Securities	Line 35	36,250,000	91,250,000	6.7546%	7.4437%		0.5028%
4								
5	Common Stock Equity		366,318,000	670,803,000	49.6550%	11.2500%		5.5862%
6								
7	Total Capitalization		827,849,000	1,350,928,000	100.0000%			9.2714%
8								
9								
10	Long-Term Debt Detail							
11	First Mortgage Bonds							
12	7.000% Series			55,000,000		7.0000%	3,850,000	
13	6.990% Series			15,000,000		6.9900%	1,048,500	
14	6.950% Series			105,000,000		6.9500%	7,297,500	
15	7.100% Series			60,000,000		7.1000%	4,260,000	
16	Pollution Control Obligations							
17	5.900% Series			6,400,000		5.9000%	377,600	
18	5.900% Series			4,000,000		5.9000%	236,000	
19	5.850% Series			7,550,000		5.8500%	441,675	
20	5.900% Series			3,400,000		5.9000%	200,600	
21	Senior Secured Debt							
22	7.530% Series			220,000,000		7.5300%	16,566,000	
23	7.330% Series			85,000,000		7.3300%	6,230,500	
24	Other Long-Term Debt							
25	Miscellaneous Seller Notes			27,525,000		8.1500%	2,243,288	
26	Amort. of Debt Disc. and Expense	Acct. 428					239,513	
27								
28	Total Long-Term Debt			588,875,000		7.3006%	42,991,176	
29								
30	Preferred Stock and Securities Detail							
31	4.500% Series			2,600,000		4.5000%	117,000	
32	8.125% Series			32,500,000		8.1250%	2,640,625	
33	7.200% Series			55,000,000		7.2000%	3,960,000	
34	6.500% Series			1,150,000		6.5000%	74,750	
35								
36	Total Preferred Stock and Securities			91,250,000		7.4437%	6,792,375	

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Exhibit___(TPH-1)
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NorthWestern Public Service
Detail for 13 Month Average Calculations
December 31, 1998 Test Year

Line No.	Description / Month / Year (a)	Total Company (b) $	Base Period Gas Factor (c)	Base Period S. Dakota Factor (d)	Base Period Allocated to South Dakota (e) $	Test Period Gas Factor (f)	Test Period S. Dakota Factor (g)	Test Period Allocated to South Dakota (h) $	Test Period Adjustment (i) $
1	PLANT IN SERVICE - COMMON		Schedule No. 11			Schedule No. 10			
2									
3	Balance - December 31, 1997	43,264,358	0.3600 E	0.5900 E	9,189,350	0.3400 E	0.5500 E	8,090,435	(1,098,915)
4	Balance - January 31, 1998	43,207,804	0.3600 E	0.5900 E	9,177,338	0.3400 E	0.5500 E	8,079,859	(1,097,479)
5	Balance - February 28, 1998	43,018,857	0.3600 E	0.5900 E	9,137,205	0.3400 E	0.5500 E	8,044,526	(1,092,679)
6	Balance - March 31, 1998	43,037,004	0.3600 E	0.5900 E	9,141,060	0.3400 E	0.5500 E	8,047,920	(1,093,140)
7	Balance - April 30, 1998	42,210,177	0.3600 E	0.5900 E	8,965,442	0.3400 E	0.5500 E	7,893,303	(1,072,139)
8	Balance - May 31, 1998	42,738,672	0.3600 E	0.5900 E	9,077,694	0.3400 E	0.5500 E	7,992,132	(1,085,562)
9	Balance - June 30, 1998	42,744,887	0.3600 E	0.5900 E	9,079,014	0.3400 E	0.5500 E	7,993,294	(1,085,720)
10	Balance - July 31, 1998	42,738,672	0.3600 E	0.5900 E	9,077,694	0.3400 E	0.5500 E	7,992,132	(1,085,562)
11	Balance - August 31, 1998	42,302,664	0.3600 E	0.5900 E	8,985,086	0.3400 E	0.5500 E	7,910,598	(1,074,488)
12	Balance - September 30, 1998	42,304,102	0.3600 E	0.5900 E	8,985,391	0.3400 E	0.5500 E	7,910,867	(1,074,524)
13	Balance - October 31, 1998	42,293,891	0.3600 E	0.5900 E	8,983,222	0.3400 E	0.5500 E	7,908,958	(1,074,264)
14	Balance - November 30, 1998	42,294,666	0.3600 E	0.5900 E	8,983,387	0.3400 E	0.5500 E	7,909,103	(1,074,284)
15	Balance - December 31, 1998	40,487,426	0.3600 E	0.5900 E	8,599,529	0.3400 E	0.5500 E	7,571,149	(1,028,380)
16									
17	Thirteen Month Total	552,643,180			117,381,412			103,344,276	(14,037,136)
18									
19	Thirteen Month Average	42,511,014			9,029,339			7,949,560	(1,079,779)
20									
21	ACCUM. DEPRECIATION - COMMON								
22									
23	Balance - December 31, 1997	5,782,135	0.3600 E	0.5900 E	1,228,125	0.3400 E	0.5500 E	1,081,259	(146,866)
24	Balance - January 31, 1998	5,920,826	0.3600 E	0.5900 E	1,257,583	0.3400 E	0.5500 E	1,107,194	(150,389)
25	Balance - February 28, 1998	5,987,780	0.3600 E	0.5900 E	1,271,804	0.3400 E	0.5500 E	1,119,715	(152,089)
26	Balance - March 31, 1998	6,046,126	0.3600 E	0.5900 E	1,284,197	0.3400 E	0.5500 E	1,130,626	(153,571)
27	Balance - April 30, 1998	5,320,428	0.3600 E	0.5900 E	1,130,059	0.3400 E	0.5500 E	994,920	(135,139)
28	Balance - May 31, 1998	5,411,146	0.3600 E	0.5900 E	1,149,327	0.3400 E	0.5500 E	1,011,884	(137,443)
29	Balance - June 30, 1998	5,545,687	0.3600 E	0.5900 E	1,177,904	0.3400 E	0.5500 E	1,037,043	(140,861)
30	Balance - July 31, 1998	5,686,717	0.3600 E	0.5900 E	1,207,859	0.3400 E	0.5500 E	1,063,416	(144,443)
31	Balance - August 31, 1998	5,383,556	0.3600 E	0.5900 E	1,143,467	0.3400 E	0.5500 E	1,006,725	(136,742)
32	Balance - September 30, 1998	5,499,198	0.3600 E	0.5900 E	1,168,030	0.3400 E	0.5500 E	1,028,350	(139,680)
33	Balance - October 31, 1998	5,629,875	0.3600 E	0.5900 E	1,195,785	0.3400 E	0.5500 E	1,052,787	(142,998)
34	Balance - November 30, 1998	7,007,704	0.3600 E	0.5900 E	1,488,436	0.3400 E	0.5500 E	1,310,441	(177,995)
35	Balance - December 31, 1998	5,266,036	0.3600 E	0.5900 E	1,118,506	0.3400 E	0.5500 E	984,749	(133,757)
36									
37	Thirteen Month Total	74,487,214			15,821,062			13,929,109	(1,891,973)
38									
39	Thirteen Month Average	5,729,786			1,217,006			1,071,470	(145,536)

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NorthWestern Public Service
Detail for 13 Month Average Calculations
December 31, 1998 Test Year

Line No	Description / Month / Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	CONSTRUCTION IN SERVICE BUT		Schedule No. 11			Schedule No. 10			
2	NOT TRANSFERRED - SD GAS								
3	Balance - December 31, 1997	1,237,701	1.0000	1.0000	1,237,701	1.0000	1.0000	1,237,701	0
4	Balance - January 31, 1998	1,533,708	1.0000	1.0000	1,533,708	1.0000	1.0000	1,533,708	0
5	Balance - February 28, 1998	1,639,016	1.0000	1.0000	1,639,016	1.0000	1.0000	1,639,016	0
6	Balance - March 31, 1998	1,759,976	1.0000	1.0000	1,759,976	1.0000	1.0000	1,759,976	0
7	Balance - April 30, 1998	829,268	1.0000	1.0000	829,268	1.0000	1.0000	829,268	0
8	Balance - May 31, 1998	359,789	1.0000	1.0000	359,789	1.0000	1.0000	359,789	0
9	Balance - June 30, 1998	1,168,732	1.0000	1.0000	1,168,732	1.0000	1.0000	1,168,732	0
10	Balance - July 31, 1998	1,411,956	1.0000	1.0000	1,411,956	1.0000	1.0000	1,411,956	0
11	Balance - August 31, 1998	1,521,900	1.0000	1.0000	1,521,900	1.0000	1.0000	1,521,900	0
12	Balance - September 30, 1998	1,773,570	1.0000	1.0000	1,773,570	1.0000	1.0000	1,773,570	0
13	Balance - October 31, 1998	3,167,206	1.0000	1.0000	3,167,206	1.0000	1.0000	3,167,206	0
14	Balance - November 30, 1998	3,765,183	1.0000	1.0000	3,765,183	1.0000	1.0000	3,765,183	0
15	Balance - December 31, 1998	3,941,589	1.0000	1.0000	3,941,589	1.0000	1.0000	3,941,589	0
16									
17	Thirteen Month Total	24,109,594			24,109,594			24,109,594	0
18									
19	Thirteen Month Average	1,854,584			1,854,584			1,854,584	0
20									
21	CONSTRUCTION IN SERVICE BUT								
22	NOT TRANSFERRED - COMMON								
23	Balance - December 31, 1997	382,952	0.3600 E	0.5900 E	81,339	0.3400 E	0.5500 E	71,612	(9,727)
24	Balance - January 31, 1998	944,264	0.3600 E	0.5900 E	200,562	0.3400 E	0.5500 E	176,577	(23,985)
25	Balance - February 28, 1998	1,045,058	0.3600 E	0.5900 E	221,970	0.3400 E	0.5500 E	195,426	(26,544)
26	Balance - March 31, 1998	954,834	0.3600 E	0.5900 E	202,807	0.3400 E	0.5500 E	178,554	(24,253)
27	Balance - April 30, 1998	948,170	0.3600 E	0.5900 E	201,391	0.3400 E	0.5500 E	177,308	(24,083)
28	Balance - May 31, 1998	270,229	0.3600 E	0.5900 E	57,397	0.3400 E	0.5500 E	50,533	(6,864)
29	Balance - June 30, 1998	340,072	0.3600 E	0.5900 E	72,231	0.3400 E	0.5500 E	63,593	(8,638)
30	Balance - July 31, 1998	422,429	0.3600 E	0.5900 E	89,724	0.3400 E	0.5500 E	78,994	(10,730)
31	Balance - August 31, 1998	483,915	0.3600 E	0.5900 E	102,784	0.3400 E	0.5500 E	90,492	(12,292)
32	Balance - September 30, 1998	667,915	0.3600 E	0.5900 E	141,865	0.3400 E	0.5500 E	124,900	(16,965)
33	Balance - October 31, 1998	712,063	0.3600 E	0.5900 E	151,242	0.3400 E	0.5500 E	133,156	(18,086)
34	Balance - November 30, 1998	1,475,835	0.3600 E	0.5900 E	313,467	0.3400 E	0.5500 E	275,981	(37,486)
35	Balance - December 31, 1998	2,604,399	0.3600 E	0.5900 E	553,174	0.3400 E	0.5500 E	487,023	(66,151)
36									
37	Thirteen Month Total	11,252,135			2,389,953			2,104,149	(285,804)
38									
39	Thirteen Month Average	865,549			183,843			161,858	(21,985)

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NorthWestern Public Service
Detail for 13 Month Average Calculations
December 31, 1998 Test Year

Line No.	Description / Month / Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	MATERIALS & SUPPLIES - SD GAS		Schedule No. 11			Schedule No. 10			
2									
3	Balance - December 31, 1997	548,566	1.0000	1.0000	548,566	1.0000	1.0000	548,566	0
4	Balance - January 31, 1998	706,859	1.0000	1.0000	706,859	1.0000	1.0000	706,859	0
5	Balance - February 28, 1998	755,996	1.0000	1.0000	755,996	1.0000	1.0000	755,996	0
6	Balance - March 31, 1998	763,761	1.0000	1.0000	763,761	1.0000	1.0000	763,761	0
7	Balance - April 30, 1998	755,494	1.0000	1.0000	755,494	1.0000	1.0000	755,494	0
8	Balance - May 31, 1998	797,930	1.0000	1.0000	797,930	1.0000	1.0000	797,930	0
9	Balance - June 30, 1998	821,743	1.0000	1.0000	821,743	1.0000	1.0000	821,743	0
10	Balance - July 31, 1998	750,862	1.0000	1.0000	750,862	1.0000	1.0000	750,862	0
11	Balance - August 31, 1998	873,989	1.0000	1.0000	873,989	1.0000	1.0000	873,989	0
12	Balance - September 30, 1998	859,197	1.0000	1.0000	859,197	1.0000	1.0000	859,197	0
13	Balance - October 31, 1998	855,667	1.0000	1.0000	855,667	1.0000	1.0000	855,667	0
14	Balance - November 30, 1998	862,097	1.0000	1.0000	862,097	1.0000	1.0000	862,097	0
15	Balance - December 31, 1998	981,479	1.0000	1.0000	981,479	1.0000	1.0000	981,479	0
16									
17	Thirteen Month Total	10,333,640			10,333,640			10,333,640	0
18									
19	Thirteen Month Average	794,895			794,895			794,895	0
20									
21	ACCUMULATED DEFERRED								
22	INCOME TAXES - GAS CREDIT								
23	Balance - December 31, 1997	839,947	1.0000	0.6386 F	536,390	1.0000	0.6420 F	539,246	2,856
24	Balance - January 31, 1998	837,917	1.0000	0.6386 F	535,094	1.0000	0.6420 F	537,943	2,849
25	Balance - February 28, 1998	835,887	1.0000	0.6386 F	533,797	1.0000	0.6420 F	536,639	2,842
26	Balance - March 31, 1998	833,857	1.0000	0.6386 F	532,501	1.0000	0.6420 F	535,336	2,835
27	Balance - April 30, 1998	831,827	1.0000	0.6386 F	531,205	1.0000	0.6420 F	534,033	2,828
28	Balance - May 31, 1998	829,797	1.0000	0.6386 F	529,908	1.0000	0.6420 F	532,730	2,822
29	Balance - June 30, 1998	827,767	1.0000	0.6386 F	528,612	1.0000	0.6420 F	531,426	2,814
30	Balance - July 31, 1998	825,737	1.0000	0.6386 F	527,316	1.0000	0.6420 F	530,123	2,807
31	Balance - August 31, 1998	823,707	1.0000	0.6386 F	526,019	1.0000	0.6420 F	528,820	2,801
32	Balance - September 30, 1998	821,677	1.0000	0.6386 F	524,723	1.0000	0.6420 F	527,517	2,794
33	Balance - October 31, 1998	819,647	1.0000	0.6386 F	523,427	1.0000	0.6420 F	526,213	2,786
34	Balance - November 30, 1998	817,617	1.0000	0.6386 F	522,130	1.0000	0.6420 F	524,910	2,780
35	Balance - December 31, 1998	2,652,108	1.0000	0.6386 F	1,693,636	1.0000	0.6420 F	1,702,653	9,017
36									
37	Thirteen Month Total	12,597,492			8,044,758			8,087,589	42,831
38									
39	Thirteen Month Average	969,038			618,828			622,122	3,294

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NorthWestern Public Service
Detail for 13 Month Average Calculations
December 31, 1998 Test Year

Line No.	Description / Month / Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	ACCUMULATED INVESTMENT		Schedule No. 11			Schedule No. 10			
2	TAX CREDIT - GAS								
3	Balance - December 31, 1997	2,659	1.0000	0.6386 F	1,698	1.0000	0.6420 F	1,707	9
4	Balance - January 31, 1998	2,281	1.0000	0.6386 F	1,457	1.0000	0.6420 F	1,464	7
5	Balance - February 28, 1998	1,903	1.0000	0.6386 F	1,215	1.0000	0.6420 F	1,222	7
6	Balance - March 31, 1998	1,525	1.0000	0.6386 F	974	1.0000	0.6420 F	979	5
7	Balance - April 30, 1998	1,147	1.0000	0.6386 F	732	1.0000	0.6420 F	736	4
8	Balance - May 31, 1998	769	1.0000	0.6386 F	491	1.0000	0.6420 F	494	3
9	Balance - June 30, 1998	391	1.0000	0.6386 F	250	1.0000	0.6420 F	251	1
10	Balance - July 31, 1998	13	1.0000	0.6386 F	8	1.0000	0.6420 F	8	0
11	Balance - August 31, 1998	0	1.0000	0.6386 F	0	1.0000	0.6420 F	0	0
12	Balance - September 30, 1998	0	1.0000	0.6386 F	0	1.0000	0.6420 F	0	0
13	Balance - October 31, 1998	0	1.0000	0.6386 F	0	1.0000	0.6420 F	0	0
14	Balance - November 30, 1998	0	1.0000	0.6386 F	0	1.0000	0.6420 F	0	0
15	Balance - December 31, 1998	0	1.0000	0.6386 F	0	1.0000	0.6420 F	0	0
16									
17	Thirteen Month Total	10,688			6,825			6,861	36
18									
19	Thirteen Month Average	822			525			528	3
20									
21	PROPANE INVENTORY - SD GAS								
22									
23	Balance - December 31, 1997	224,775	1.0000	1.0000	224,775	1.0000	1.0000	224,775	0
24	Balance - January 31, 1998	224,267	1.0000	1.0000	224,267	1.0000	1.0000	224,267	0
25	Balance - February 28, 1998	223,675	1.0000	1.0000	223,675	1.0000	1.0000	223,675	0
26	Balance - March 31, 1998	223,400	1.0000	1.0000	223,400	1.0000	1.0000	223,400	0
27	Balance - April 30, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
28	Balance - May 31, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
29	Balance - June 30, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
30	Balance - July 31, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
31	Balance - August 31, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
32	Balance - September 30, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
33	Balance - October 31, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
34	Balance - November 30, 1998	222,461	1.0000	1.0000	222,461	1.0000	1.0000	222,461	0
35	Balance - December 31, 1998	221,987	1.0000	1.0000	221,987	1.0000	1.0000	221,987	0
36									
37	Thirteen Month Total	2,897,792			2,897,792			2,897,792	0
38									
39	Thirteen Month Average	222,907			222,907			222,907	0

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NorthWestern Public Service
Detail for 13 Month Average Calculations
December 31, 1998 Test Year

Line No.	Description / Month / Year	Total Company	Base Period Gas Factor	Base Period S. Dakota Factor	Base Period Allocated to South Dakota	Test Period Gas Factor	Test Period S. Dakota Factor	Test Period Allocated to South Dakota	Test Period Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		$			$			$	$
1	NATURAL GAS STORAGE - SD GAS		Schedule No. 11			Schedule No. 10			
2									
3	Balance - December 31, 1997	1,127,205	1.0000	1.0000	1,127,205	1.0000	1.0000	1,127,205	0
4	Balance - January 31, 1998	803,607	1.0000	1.0000	803,607	1.0000	1.0000	803,607	0
5	Balance - February 28, 1998	501,523	1.0000	1.0000	501,523	1.0000	1.0000	501,523	0
6	Balance - March 31, 1998	261,058	1.0000	1.0000	261,058	1.0000	1.0000	261,058	0
7	Balance - April 30, 1998	93,962	1.0000	1.0000	93,962	1.0000	1.0000	93,962	0
8	Balance - May 31, 1998	0	1.0000	1.0000	0	1.0000	1.0000	0	0
9	Balance - June 30, 1998	278,022	1.0000	1.0000	278,022	1.0000	1.0000	278,022	0
10	Balance - July 31, 1998	592,938	1.0000	1.0000	592,938	1.0000	1.0000	592,938	0
11	Balance - August 31, 1998	788,262	1.0000	1.0000	788,262	1.0000	1.0000	788,262	0
12	Balance - September 30, 1998	1,015,976	1.0000	1.0000	1,015,976	1.0000	1.0000	1,015,976	0
13	Balance - October 31, 1998	1,252,202	1.0000	1.0000	1,252,202	1.0000	1.0000	1,252,202	0
14	Balance - November 30, 1998	1,231,570	1.0000	1.0000	1,231,570	1.0000	1.0000	1,231,570	0
15	Balance - December 31, 1998	1,184,485	1.0000	1.0000	1,184,485	1.0000	1.0000	1,184,485	0
16									
17	Thirteen Month Total	9,130,810			9,130,810			9,130,810	0
18									
19	Thirteen Month Average	702,370			702,370			702,370	0

NorthWestern Public Service
Accumulated Depreciation and Amortization
Direct South Dakota Gas Plant
December 31, 1998 Test Year

Line No.	Month / Year (a)	Production (b) $	Distribution (c) $	General (d) $	Undistributed (e) $	Amortization (f) $	Total (g) $
1	Balance - December 31, 1997	534,855	12,753,184	429,023	(72,171)	147	13,645,038
2	Balance - January 31, 1998	538,182	12,847,230	418,783	(14,724)	171	13,789,642
3	Balance - February 28, 1998	541,509	12,950,254	386,564	248	195	13,878,770
4	Balance - March 31, 1998	544,836	13,046,776	429,770	(43,962)	220	13,977,640
5	Balance - April 30, 1998	548,163	13,144,155	426,666	(89,800)	244	14,029,428
6	Balance - May 31, 1998	551,490	13,241,585	435,475	(103,284)	269	14,125,555
7	Balance - June 30, 1998	554,817	13,338,964	445,304	(42,365)	293	14,297,013
8	Balance - July 31, 1998	558,144	13,439,012	443,284	(114,024)	317	14,326,733
9	Balance - August 31, 1998	561,471	13,438,893	432,457	(81,103)	342	14,352,060
10	Balance - September 30, 1998	564,798	13,538,530	453,821	(76,853)	366	14,480,662
11	Balance - October 31, 1998	568,125	13,572,852	473,414	(84,147)	427	14,530,671
12	Balance - November 30, 1998	571,452	13,672,317	483,349	(86,695)	488	14,640,911
13	Balance - December 31, 1998	574,779	13,769,049	481,095	(92,977)	549	14,732,495
14							
15	Thirteen Month Total	7,212,621	172,752,801	5,739,005	(901,837)	4,028	184,806,618
16							
17	Thirteen Month Average	554,817	13,288,677	441,462	(69,372)	310	14,215,894

NorthWestern Public Service
Basis for Allocation of Undistributed Expense
Twelve Months Ending December 31, 1998 - Test Period Details
Factors Based on Actual 1998 Data

Line No.	Basis of Factor	Factor No.	Electric	Gas	Total	Gas Only		
						Nebraska	S. Dakota	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customers	A						
2	Value		55,886	78,912	134,798	39,836	39,076	78,912
3	Percentage of Total		41.46%	58.54%	100.00%	50.48%	49.52%	100.00%
4								
5	Gross Revenues	B						
6	Value		$73,604,616	$59,516,356	$133,120,972	$29,841,073	$29,675,283	$59,516,356
7	Percentage of Total		55.29%	44.71%	100.00%	50.14%	49.86%	100.00%
8								
9	Direct Expenses, Less Fuel and Gas	C						
10	Value		$10,735,874	$5,314,189	$16,050,063	$2,465,061	$2,849,128	$5,314,189
11	Percentage of Total		66.89%	33.11%	100.00%	46.39%	53.61%	100.00%
12								
13	Direct Payroll Charged to Construction,	D						
14	Operations and Maintenance							
15	Value		$4,615,354	$3,064,362	$7,679,716	$1,470,239	$1,594,123	$3,064,362
16	Percentage of Total		60.10%	39.90%	100.00%	47.98%	52.02%	100.00%
17								
18	Composite of 4 Factors (B, C, D & F)	E						
19	Value		263.12%	136.88%	400.00%	180.31%	219.69%	400.00%
20	Percentage of Total		66.00%	34.00%	100.00%	45.00%	55.00%	100.00%
21								
22	Net Plant in Service	F						
23	Value		$177,325,974	$42,020,395	$219,346,369	$15,042,398	$26,977,997	$42,020,395
24	Percentage of Total		80.84%	19.16%	100.00%	35.80%	64.20%	100.00%
25								
26	Net Revenue	G						
27	Value		$63,011,213	$18,367,660	$81,378,873			
28	Percentage of Total		77.43%	22.57%	100.00%			
29								
30	Payroll Charged to Construction	H						
31	Value		$1,634,485	$1,110,058	$2,744,543			
32	Percentage of Total		59.55%	40.45%	100.00%			
33								
34	O&M Expenses, Less Gas & Prod.	I						
35	Value					$5,066,029	$6,292,486	$11,358,515
36	Percentage of Total					44.60%	55.40%	100.00%

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NorthWestern Public Service
Basis for Allocation of Undistributed Expense
Twelve Months Ending December 31, 1998 - Base Period Details
Factors Based on Actual 1997 Data

Line No.	Basis of Factor	Factor No.	Electric	Gas	Total	Gas Only		
						Nebraska	S. Dakota	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customers	A						
2	Value		55,800	78,531	134,331	39,702	38,829	78,531
3	Percentage of Total		41.54%	58.46%	100.00%	50.56%	49.44%	100.00%
4								
5	Gross Revenues	B						
6	Value		$73,328,723	$73,371,022	$146,699,745	$33,354,958	$40,016,064	$73,371,022
7	Percentage of Total		49.99%	50.01%	100.00%	45.46%	54.54%	100.00%
8								
9	Direct Expenses, Less Fuel and Gas	C						
10	Value		$11,494,550	$5,127,602	$16,622,152	$2,308,693	$2,818,909	$5,127,602
11	Percentage of Total		69.15%	30.85%	100.00%	45.02%	54.98%	100.00%
12								
13	Direct Payroll Charged to Construction,	D						
14	Operations and Maintenance							
15	Value		$4,468,702	$3,381,855	$7,850,557	$1,235,461	$2,146,394	$3,381,855
16	Percentage of Total		56.92%	43.08%	100.00%	36.53%	63.47%	100.00%
17								
18	Composite of 4 Factors (B, C, D & F)	E						
19	Value		257.00%	143.00%	400.00%	163.15%	236.85%	400.00%
20	Percentage of Total		64.00%	36.00%	100.00%	41.00%	59.00%	100.00%
21								
22	Net Plant in Service	F						
23	Value		$178,303,991	$41,995,461	$220,299,452	$15,177,160	$26,818,301	$41,995,461
24	Percentage of Total		80.94%	19.06%	100.00%	36.14%	63.86%	100.00%
25								
26	Net Revenue	G						
27	Value		$62,165,841	$20,883,283	$83,049,124			
28	Percentage of Total		74.85%	25.15%	100.00%			
29								
30	Payroll Charged to Construction	H						
31	Value		$1,594,197	$1,105,273	$2,699,470			
32	Percentage of Total		59.06%	40.94%	100.00%			
33								
34	O&M Expenses, Less Gas & Prod.	I						
35	Value					$5,229,985	$6,691,370	$11,921,355
36	Percentage of Total					43.87%	56.13%	100.00%

NorthWestern Public Service
Class Cost of Service Study
Income Statement-Proposed Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description		Reference	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)		(b)	(c)	(d)	(e)	(f)
1	Revenues:						
2	Gas sales and transportation revenues (non-gas cost)						
3	Class cost of service required level		Pg. 2, Ln. 2	13,917,374	8,856,610	2,686,001	2,374,763
4	Shared differential between class and total % change	0%	Calculated	0	0	0	0
5	Total			13,917,374	8,856,610	2,686,001	2,374,763
6	Other revenues		Pg. 9, Ln. 29	363,297	135,570	64,656	163,071
7							
8	Total Revenues			14,280,671	8,992,180	2,750,657	2,537,834
9							
10	Expenses:						
11	Operations & maintenance expenses		Pg. 34, Ln. 47	5,686,153	3,816,344	924,929	944,880
12	Depreciation & amortization expense		Pg. 35, Ln. 29	1,616,790	975,073	342,594	299,123
13	Taxes other than income taxes		Pg. 36, Ln. 29	977,019	589,232	207,029	180,758
14	MGP removal cost		Pg. 36, Ln. 38	1,310,392	790,288	277,669	242,435
15	Rate case expense		Pg. 33, Ln. 38	50,000	32,568	8,541	8,891
16							
17	Total Expenses			9,640,354	6,203,505	1,760,762	1,676,087
18							
19	Operating Income Before Income Taxes			4,640,317	2,788,675	989,895	861,747
20							
21	Federal and State Income Taxes			1,212,276	728,537	258,609	225,130
22							
23	Net Operating Income			3,428,041	2,060,138	731,286	636,617
24							
25							
26	Rate Base		Pg. 15, Ln. 40	36,974,359	22,220,348	7,887,548	6,866,463
27							
28							
29	Return on Rate Base			9.27%	9.27%	9.27%	9.27%
30							
31							
32	Return on Equity			11.25%	11.25%	11.25%	11.25%
33							
34	Federal and State Effective Tax Rate		35.00%				
35							
36	Capital Ratios						
37	Long-term debt		43.5904%				
38	Preferred stock & securities		6.7546%				
39	Common stock equity		49.6550%				
40							
41	Weighted Cost of Capital						
42	Long-term debt		3.1824%				
43	Preferred stock & securities		0.5028%				
44	Common stock equity		5.5862%				

Exhibit___(TPH-2)
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NorthWestern Public Service
Class Cost of Service Study
Income Statement-Required Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description (a)	Reference (b)	Total Service Area (c)	Residential (d)	Small Commercial (e)	Large Commercial (f)
1	Revenues:					
2	Gas sales and transportation revenues (non-gas cost)	Calculated	13,917,374	8,858,610	2,666,001	2,374,763
3	Other revenues	Pg. 9, Ln. 29	363,297	135,570	84,656	163,071
4						
5	Total Revenues		14,280,671	8,992,180	2,750,657	2,537,834
6						
7	Expenses:					
8	Operations & maintenance expenses	Pg. 34, Ln. 47	5,686,153	3,616,344	924,929	944,880
9	Depreciation & amortization expense	Pg. 35, Ln. 29	1,616,790	975,073	342,594	299,123
10	Taxes other than income taxes	Pg. 36, Ln. 29	977,019	589,232	207,029	180,758
11	MGP removal cost	Pg. 36, Ln. 38	1,310,392	790,288	277,669	242,435
12	Rate case expense	Pg. 33, Ln. 38	50,000	32,568	8,541	8,891
13						
14	Total Expenses		9,640,354	6,203,505	1,760,762	1,676,087
15						
16	Operating Income Before Income Taxes		4,640,317	2,788,675	989,895	861,747
17						
18	Federal and State Income Taxes		1,212,278	728,537	258,609	225,130
19						
20	Net Operating Income		3,428,041	2,060,138	731,286	636,617
21						
22						
23	Rate Base	Pg. 15, Ln. 40	36,974,359	22,220,348	7,887,548	6,866,463
24						
25						
26	Return on Rate Base		9.27%	9.27%	9.27%	9.27%
27						
28						
29	Return on Equity		11.25%	11.25%	11.25%	11.25%
30						
31	Federal and State Effective Tax Rate	35.00%				
32						
33	Capital Ratios					
34	Long-term debt	43.5904%				
35	Preferred stock & securities	6.7546%				
36	Common stock equity	49.6550%				
37						
38	Weighted Cost of Capital					
39	Long-term debt	3.1824%				
40	Preferred stock & securities	0.5028%				
41	Common stock equity	5.5862%				

Exhibit___(TPH-2)
Page 2 of 37

NorthWestern Public Service
Class Cost of Service Study
Income Statement-Present Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description (a)	Reference (b)	Total Service Area (c)	Residential (d)	Small Commercial (e)	Large Commercial (f)
1	Revenues:					
2	Gas sales and transportation revenues (non-gas cost)	Pg. 10, Ln. 16	11,811,783	7,570,923	2,191,588	2,049,272
3	Other revenues	Pg. 10, Ln. 29	363,297	135,570	64,656	163,071
4						
5	Total Revenues		12,175,080	7,706,493	2,256,244	2,212,343
6						
7	Expenses					
8	Operations & maintenance expenses	Pg. 34, Ln. 47	5,686,153	3,816,344	924,929	944,880
9	Depreciation & amortization expense	Pg. 35, Ln. 29	1,616,790	975,073	342,594	299,123
10	Taxes other than income taxes	Pg. 36, Ln. 29	977,019	589,232	207,029	180,758
11	MGP removal cost	Pg. 36, Ln. 38	1,318,450	795,148	279,376	243,926
12	Rate case expense	Pg. 33, Ln. 38	50,000	32,568	8,541	8,891
13						
14	Total Expenses		9,648,412	6,208,365	1,762,469	1,677,578
15						
16	Operating Income Before Income Taxes		2,526,668	1,498,128	493,775	534,765
17						
18	Federal and State Income Taxes		472,499	276,846	84,967	110,686
19						
20	Net Operating Income		2,054,169	1,221,282	408,808	424,079
21						
22						
23	Rate Base	Pg. 15, Ln. 40	36,974,359	22,220,348	7,887,548	6,866,463
24						
25						
26	Return on Rate Base		5.56%	5.50%	5.18%	6.18%
27						
28						
29	Return on Equity		3.77%	3.65%	3.02%	5.02%
30						
31	Federal and State Effective Tax Rate	35.00%				
32						
33	Capital Ratios					
34	Long-term debt	43.5904%				
35	Preferred stock & securities	6.7546%				
36	Common stock equity	49.6550%				
37						
38	Weighted Cost of Capital					
39	Long-term debt	3.1824%				
40	Preferred stock & securities	0.5028%				
41	Common stock equity	1.8705%				

Exhibit___(TPH-2)
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NorthWestern Public Service
Class Cost of Service Study
Customer Charge
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Reference		Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)		(c)	(d)	(e)	(f)
1	Customer Rate Base						
2							
3	Gas plant in service	Pg. 16, Ln. 5		20,442,359	15,591,962	2,740,466	2,109,931
4	Accumulated reserve for depreciation	Pg. 16, Ln. 6		(6,122,936)	(4,670,135)	(820,830)	(631,971)
5	Working capital	Pg. 16, Ln. 7		394,543	302,364	52,785	39,394
6	Accumulated deferred income taxes	Pg. 16, Ln. 8		(249,385)	(190,213)	(33,432)	(25,740)
7							
8							
9	Total Customer Rate Base	Pg. 16, Ln. 10		14,464,581	11,033,978	1,938,989	1,491,614
10							
11	Rate of Return on Rate Base	Sch. 9.2, Ln. 7		9.27%	9.27%	9.27%	9.27%
12							
13	Return on Rate Base			1,341,069	1,023,004	179,771	138,294
14							
15	Federal and State Income Taxes	Sch. 7, Ln. 22		474,249	361,770	63,573	48,906
16							
17	Rate Case Expense	Pg. 33, Ln. 34		30,468	23,813	4,041	2,614
18							
19	Distribution Oper. & Maint. Expenses	Pg. 26, Ln. 13		602,100	393,533	87,598	120,975
20							
21	Customer Accounts Expenses	Pg. 28, Ln. 13		951,167	806,880	118,539	25,748
22							
23	Customer Service & Information Expenses	Pg. 30, Ln. 6		813,418	690,023	101,374	22,021
24							
25	Administrative & General Expenses	Pg. 34, Ln. 35		1,370,805	1,071,386	181,833	117,586
26							
27	Depreciation Expense	Pg. 35, Ln. 25		847,560	493,911	86,811	66,838
28							
29	Taxes Other Than Income Taxes	Pg. 36, Ln. 25		391,319	298,469	52,460	40,390
30							
31	MGP Removal Cost	Pg. 38, Ln. 34		524,842	400,312	70,359	54,171
32							
33							
34	Customer Charge Revenue Requirement			7,147,003	5,563,101	946,359	637,543
35							
36	Number of Annual Bills	Pg. 7, Ln. 1	times 12	464,000	400,847	58,889	4,264
37							
38							
39	Monthly Customer Charge Requirement			15.40	13.88	16.07	149.52

NorthWestern Public Service
Class Cost of Service Study
Classification Ratios
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Classification Ratio Number	Total	Customer	Demand	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
1	CUSTOMER CLASSIFIER	Ratio C-1				
2	Ratio C-1		1.00000000	1.00000000	0.00000000	0.00000000
3						
4	DEMAND CLASSIFIER	Ratio C-2				
5	Ratio C-2		1.00000000	0.00000000	1.00000000	0.00000000
6						
7	COMMODITY CLASSIFIER	Ratio C-3				
8	Ratio C-3		1.00000000	0.00000000	0.00000000	1.00000000
9						
10	DISTRIBUTION MAINS CLASSIFIER	Ratio C-4				
11	Ratio C-4		1.00000000	0.00000000	0.95000000	0.05000000
12						
13	COMPOSITE MAINS/SERVICES CLASSIFIER	Ratio C-5				
14	Account 376 C-4		19,417,937	0	18,447,040	970,897
15	Account 380 C-1		8,525,293	8,525,293	0	0
16						
17	Totals		27,943,230	8,525,293	18,447,040	970,897
18						
19	Ratio C-5		1.00000000	0.30509333	0.66016133	0.03474534
20						
21	PAYROLL CLASSIFIER	Ratio C-6				
22	Total Payroll Costs other than A & G					
23	Customer		1,385,756	1,385,756	0	0
24	Demand		175,725	0	175,725	0
25	Commodity		446,416	0	0	446,416
26						
27	Totals		2,007,897	1,385,756	175,725	446,416
28						
29	Ratio C-6		1.00000000	0.69015293	0.08751694	0.22233013
30						
31	DISTRIBUTION PLANT CLASSIFIER	Ratio C-7				
32	Total Distribution Plant in Service					
33	Customer		15,206,117	15,206,117	0	0
34	Demand		20,267,022	0	20,267,022	0
35	Commodity		2,492,541	0	0	2,492,541
36						
37	Totals		37,965,680	15,206,117	20,267,022	2,492,541
38						
39	Ratio C-7		1.00000000	0.40052271	0.53382481	0.06565248

NorthWestern Public Service
Class Cost of Service Study
Classification Ratios
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Classification Ratio Number	Total	Customer	Demand	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
1	COMPOSITE LABOR/PLANT CLASSIFIER	Ratio C-8				
2	Labor Related Admin. & General Costs					
3	Customer		912,760	912,760	0	0
4	Demand		115,746	0	115,746	0
5	Commodity		294,042	0	0	294,042
6						
7	Totals		1,322,548	912,760	115,746	294,042
8						
9	Plant Related Admin. & General Costs					
10	Customer		204,934	204,934	0	0
11	Demand		273,139	0	273,139	0
12	Commodity		33,592	0	0	33,592
13						
14	Totals		511,665	204,934	273,139	33,592
15						
16	Total of Labor and Plant Related Costs		1,834,213	1,117,694	388,885	327,634
17						
18	Ratio C-8		1.00000000	0.60935889	0.21201736	0.17862375
19						
20	DISTRIBUTION OPERATIONS CLASSIFIER	Ratio C-9				
21	Total Distributions Operations Expense, Less S&E					
22	Customer		229,187	143,741	33,870	51,575
23	Demand		281,591	144,062	77,289	60,240
24	Commodity		456,639	170,401	81,270	204,968
25						
26	Totals		967,415	458,204	192,429	316,783
27						
28	Ratio C-9		1.00000000	0.47363753	0.19891009	0.32745308
29						
30	DISTRIBUTION MAINTENANCE CLASSIFIER	Ratio C-10				
31	Total Distributions Maintenance Expense, Less S&E					
32	Customer		125,551	90,767	17,508	17,276
33	Demand		31,534	16,133	8,655	6,746
34	Commodity		16,003	5,972	2,848	7,183
35						
36	Totals		173,088	112,872	29,011	31,205
37						
38	Ratio C-10		1.00000000	0.65210760	0.16760838	0.18028402

NorthWestern Public Service
Class Cost of Service Study
Allocation Ratios
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Allocation Ratio Number	Total	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)
1	CUSTOMERS	Ratio A-1	38,667	33,404	4,907	355
2	Ratio A-1		1.00000000	0.86389439	0.12691595	0.00918966
3						
4	PEAK DAY MMBTU THROUGHPUT-FEB 1, 1996	Ratio A-2	70,958	36,302	19,476	15,180
5	Ratio A-2		1.00000000	0.51159841	0.27447222	0.21392937
6						
7	WEATHER NORMALIZED MMBTU THROUGHPUT	Ratio A-3	8,896,343	3,319,779	1,583,299	3,993,265
8	Ratio A-3		1.00000000	0.37316221	0.17797189	0.44886590
9						
10	METERS	Ratio A-4	49,648	33,404	7,361	8,883
11	Ratio A-4		1.00000000	0.67281608	0.14826403	0.17891989
12						
13	REGULATORS	Ratio A-5	46,450	33,404	7,361	5,685
14	Ratio A-5		1.00000000	0.71913835	0.15847176	0.12238989
15						
16	SERVICES	Ratio A-6	40,443	33,404	4,907	2,132
17	Ratio A-6		1.00000000	0.82595221	0.12133151	0.05271628
18						
19	CUSTOMER ACCOUNTS	Ratio A-7	39,377	33,404	4,907	1,066
20	Ratio A-7		1.00000000	0.84830317	0.12462542	0.02707141
21						
22	RESIDENTIAL REVENUE	Ratio A-8	1	1	0	0
23	Ratio A-8		1.00000000	1.00000000	0.00000000	0.00000000
24						
25	SMALL COMMERCIAL REVENUE	Ratio A-9	1	0	1	0
26	Ratio A-9		1.00000000	0.00000000	1.00000000	0.00000000
27						
28	LARGE COMMERCIAL & INDUSTRIAL REVENUE	Ratio A-10	1	0	0	1
29	Ratio A-10		1.00000000	0.00000000	0.00000000	1.00000000
30						
31	CUSTOMER DISTRIBUTION PLANT	Ratio A-11	15,206,117	11,598,133	2,038,505	1,569,479
32	Ratio A-11		1.00000000	0.76272812	0.13405822	0.10321366
33						
34	DEMAND DISTRIBUTION PLANT	Ratio A-12	20,267,022	10,368,575	5,562,735	4,335,712
35	Ratio A-12		1.00000000	0.51159835	0.27447224	0.21392941
36						
37	COMMODITY DISTRIBUTION PLANT	Ratio A-13	2,492,541	930,122	443,602	1,118,817
38	Ratio A-13		1.00000000	0.37316216	0.17797180	0.44886604

NorthWestern Public Service
Class Cost of Service Study
Allocation Ratios
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Allocation Ratio Number	Total	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)
1	CUSTOMER COMPOSITE MAINS/SERVICES PLANT	Ratio A-14	8,525,293	7,041,484	1,034,387	449,422
2	Ratio A-14		1.00000000	0.82595214	0.12133155	0.05271631
3						
4	DEMAND COMPOSITE MAINS/SERVICES PLANT	Ratio A-15	18,447,040	9,437,476	5,063,200	3,946,364
5	Ratio A-15		1.00000000	0.51159839	0.27447222	0.21392939
6						
7	COMMODITY COMPOSITE MAINS/SERVICES PLANT	Ratio A-16	970,897	362,302	172,792	435,803
8	Ratio A-16		1.00000000	0.37316214	0.17797150	0.44886636
9						
10	CUSTOMER PAYROLL COSTS	Ratio A-17	1,385,756	1,088,933	183,378	113,445
11	Ratio A-17		1.00000000	0.78580428	0.13233066	0.08186506
12						
13	DEMAND PAYROLL COSTS	Ratio A-18	175,725	89,901	48,231	37,593
14	Ratio A-18		1.00000000	0.51160051	0.27446863	0.21393086
15						
16	COMMODITY PAYROLL COSTS	Ratio A-19	446,416	166,586	79,450	200,380
17	Ratio A-19		1.00000000	0.37316315	0.17797301	0.44886384
18						
19	CUSTOMER COMPOSITE LABOR/PLANT A & G	Ratio A-20	1,117,694	873,560	148,259	95,875
20	Ratio A-20		1.00000000	0.78157349	0.13264722	0.08577929
21						
22	DEMAND COMPOSITE LABOR/PLANT A & G	Ratio A-21	388,885	198,951	106,738	83,196
23	Ratio A-21		1.00000000	0.51159340	0.27447189	0.21393471
24						
25	COMMODITY COMPOSITE LABOR/PLANT A & G	Ratio A-22	327,634	122,258	58,311	147,065
26	Ratio A-22		1.00000000	0.37315419	0.17797603	0.44886978
27						
28	CUSTOMER COMPOSITE DISTRIBUTION OPER.	Ratio A-23	229,187	143,741	33,870	51,575
29	Ratio A-23		1.00000000	0.62718217	0.14778325	0.22503458
30						
31	DEMAND COMPOSITE DISTRIBUTION OPER.	Ratio A-24	281,591	144,062	77,289	60,240
32	Ratio A-24		1.00000000	0.51160016	0.27447255	0.21392729
33						
34	COMMODITY COMPOSITE DISTRIBUTION OPER.	Ratio A-25	456,639	170,401	81,270	204,968
35	Ratio A-25		1.00000000	0.37316348	0.17797429	0.44886223
36						
37	CUSTOMER COMPOSITE DISTRIBUTION MAINT.	Ratio A-26	125,551	90,767	17,508	17,276
38	Ratio A-26		1.00000000	0.72294924	0.13944931	0.13760145
39						
40	DEMAND COMPOSITE DISTRIBUTION MAINT.	Ratio A-27	31,534	16,133	8,655	6,746
41	Ratio A-27		1.00000000	0.51160652	0.27446566	0.21392782
42						
43	COMMODITY COMPOSITE DISTRIBUTION MAINT.	Ratio A-28	16,003	5,972	2,848	7,183
44	Ratio A-28		1.00000000	0.37318003	0.17796663	0.44885334

NorthWestern Public Service
Class Cost of Service Study
Operating Revenues-Proposed Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(o)	(f)	(g)	(h)
1	GAS SERVICE REVENUES (NON-GAS COST)	480-481						
2		489						
3	Normalized therms					33,197,790	15,832,990	39,932,650
4								
5	Times average rate per therm					0.1943	0.1436	0.0465
6								
7	Non-customer charge revenues				10,581,949	6,451,528	2,273,778	1,856,643
8								
9								
10	Annual bills					400,847	58,889	4,264
11								
12	Times average monthly customer charge					6.0000	7.0000	121.5103
13								
14	Customer charge revenues				3,335,425	2,405,082	412,223	518,120
15								
16	Total Gas Service Revenues				13,917,374	8,856,610	2,686,001	2,374,763
17								
18								
19	OTHER REVENUES							
20								
21	Late payment fees	487	C-3	A-3	90,758	33,868	16,152	40,738
22								
23	Miscellaneous service revenues	488	C-3	A-3	72,456	27,038	12,895	32,523
24								
25	Transportation revenues (contracts with deviation)	489	C-3	A-3	199,374	74,399	35,483	89,492
26								
27	Other gas revenues	495	C-3	A-3	709	265	126	318
28								
29	Total Other Revenues				363,297	135,570	64,656	163,071
30								
31								
32	TOTAL REVENUES				14,280,671	8,992,180	2,750,657	2,537,834

NorthWestern Public Service
Class Cost of Service Study
Operating Revenues-Present Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	GAS SERVICE REVENUES (NON-GAS COST)	480-481						
2								
3	Normalized therms					33,197,790	15,832,990	39,932,650
4								
5	Times average rate per therm					0.1737	0.1217	0.0407
6								
7	Non-customer charge revenues				9,319,090	5,767,111	1,926,587	1,625,392
8								
9								
10	Annual bills					400,847	58,869	4,264
11								
12	Times average monthly customer charge					4.5000	4.5000	99.4090
13								
14	Customer charge revenues				2,492,693	1,803,812	265,001	423,880
15								
16	Total Gas Service Revenues				11,811,783	7,570,923	2,191,588	2,049,272
17								
18								
19	OTHER REVENUES							
20								
21	Late payment fees	487	C-3	A-3	90,758	33,868	16,152	40,738
22								
23	Miscellaneous service revenues	488	C-3	A-3	72,456	27,038	12,895	32,523
24								
25	Transportation revenues (contracts with deviation)	489	C-3	A-3	199,374	74,399	35,483	89,492
26								
27	Other gas revenues	495	C-3	A-3	709	265	126	318
28								
29	Total Other Revenues				363,297	135,570	64,656	163,071
30								
31								
32	TOTAL REVENUES				12,175,080	7,706,493	2,256,244	2,212,343

Exhibit___(TPH-2)
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NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	GAS PLANT IN SERVICE							
2								
3	Distribution Plant							
4								
5	Land and land rights	374						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	201,417	75,161	35,847	90,409
9								
10	Totals		C-3		201,417	75,161	35,847	90,409
11								
12	Structures and improvements	375						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	62,095	23,172	11,051	27,872
16								
17	Totals		C-3		62,095	23,172	11,051	27,872
18								
19	Mains	376						
20	Customer			A-6	0	0	0	0
21	Demand			A-2	18,447,040	9,437,476	5,063,200	3,946,364
22	Commodity			A-3	970,697	362,302	172,792	435,603
23								
24	Totals		C-4		19,417,937	9,799,778	5,235,992	4,382,167
25								
26	Compressor station equipment	377						
27	Customer				0	0	0	0
28	Demand			A-2	0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-2		0	0	0	0
32								
33	Measuring and reg. station equipment-gen.	378						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	497,796	185,758	88,594	223,444
37								
38	Totals		C-3		497,796	185,758	88,594	223,444
39								
40	Measuring and reg. sta. equip.-c. gate	379						
41	Customer				0	0	0	0
42	Demand				0	0	0	0
43	Commodity			A-3	760,336	283,729	135,318	341,289
44								
45	Totals		C-3		760,336	283,729	135,318	341,289

NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	GAS PLANT IN SERVICE							
2								
3	Distribution Plant							
4								
5	Services	380						
6	Customer			A-6	8,525,293	7,041,484	1,034,387	449,422
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals		C-1		8,525,293	7,041,484	1,034,387	449,422
11								
12	Meters	381						
13	Customer			A-4	3,912,117	2,632,135	580,026	699,956
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals		C-1		3,912,117	2,632,135	580,026	699,956
18								
19	Meter installations	382						
20	Customer			A-4	1,437,108	966,910	213,071	257,127
21	Demand				0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-1		1,437,108	966,910	213,071	257,127
25								
26	Regulators	383						
27	Customer			A-5	807,726	580,867	128,002	98,857
28	Demand				0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-1		807,726	580,867	128,002	98,857
32								
33	Regulator installations	384						
34	Customer			A-5	523,873	376,737	83,019	64,117
35	Demand				0	0	0	0
36	Commodity				0	0	0	0
37								
38	Totals		C-1		523,873	376,737	83,019	64,117
39								
40	Production land and land rights	304						
41	Customer				0	0	0	0
42	Demand			A-2	49,650	25,400	13,628	10,622
43	Commodity				0	0	0	0
44								
45	Totals		C-2		49,650	25,400	13,628	10,622

NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	GAS PLANT IN SERVICE							
2								
3	Distribution Plant							
4								
5	Production structures and improvements	305						
6	Customer				0	0	0	0
7	Demand			A-2	263,049	134,575	72,200	56,274
8	Commodity				0	0	0	0
9								
10	Totals		C-2		263,049	134,575	72,200	56,274
11								
12	Production LPG equipment and other equipment	311/320						
13	Customer				0	0	0	0
14	Demand			A-2	1,507,283	771,124	413,707	322,452
15	Commodity				0	0	0	0
16								
17	Totals		C-2		1,507,283	771,124	413,707	322,452
18								
19	Total Distribution Plant							
20	Customer				15,206,117	11,598,133	2,038,505	1,569,479
21	Demand				20,267,022	10,368,575	5,562,735	4,335,712
22	Commodity				2,492,541	930,122	443,602	1,118,817
23								
24	Totals				37,965,680	22,896,830	8,044,842	7,024,008
25								
26	General and Intangible Plant, Plus Constr. In Service	389-399						
27	Customer	301-303		A-11	5,236,242	3,993,829	701,951	540,462
28	Demand			A-12	6,978,970	3,570,429	1,915,534	1,493,007
29	Commodity			A-13	858,309	320,288	152,755	385,266
30								
31	Totals		C-7		13,073,521	7,884,546	2,770,250	2,418,725
32								
33	Total Gas Plant in Service							
34	Customer				20,442,359	15,591,962	2,740,466	2,109,931
35	Demand				27,245,992	13,939,004	7,478,269	5,828,719
36	Commodity				3,350,850	1,250,410	596,357	1,504,083
37								
38	Totals				51,039,201	30,781,376	10,815,092	9,442,733

NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	ACCUMULATED RESERVE FOR DEPRECIATION							
2								
3	Direct South Dakota Gas Plant	304-387						
4	Customer			A-11	(5,693,788)	(4,342,812)	(763,299)	(587,677)
5	Demand			A-12	(7,588,797)	(3,862,416)	(2,082,914)	(1,623,467)
6	Commodity			A-13	(933,309)	(348,275)	(166,103)	(418,931)
7								
8	Totals		C-7		(14,215,894)	(8,573,503)	(3,012,316)	(2,630,075)
9								
10	Common Plant	389-399						
11	Customer	301-303		A-11	(429,148)	(327,323)	(57,531)	(44,294)
12	Demand			A-12	(571,977)	(292,622)	(156,992)	(122,363)
13	Commodity			A-13	(70,345)	(26,251)	(12,519)	(31,575)
14								
15	Totals		C-7		(1,071,470)	(646,196)	(227,042)	(198,232)
16								
17	Total Accumulated Reserve for Depreciation							
18	Customer				(6,122,936)	(4,670,135)	(820,830)	(631,971)
19	Demand				(8,160,774)	(4,175,038)	(2,239,906)	(1,745,830)
20	Commodity				(1,003,654)	(374,526)	(178,622)	(450,506)
21								
22	Totals				(15,287,364)	(9,219,699)	(3,239,358)	(2,828,307)
23								
24	WORKING CAPITAL							
25								
26	Materials and supplies	154						
27	Customer			A-11	318,373	242,832	42,681	32,860
28	Demand			A-12	424,335	217,089	118,468	90,778
29	Commodity			A-13	52,187	19,474	9,288	23,425
30								
31	Totals		C-7		794,895	479,395	168,437	147,063
32								
33	Storage gas and fuel	151						
34	Customer					0	0	0
35	Demand			A-2	925,277	473,370	253,963	197,944
36	Commodity				0	0	0	0
37								
38	Totals		C-2		925,277	473,370	253,963	197,944

NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	WORKING CAPITAL							
2								
3	Total Working Capital							
4	Customer				318,373	242,832	42,681	32,860
5	Demand				1,349,612	690,459	370,431	288,722
6	Commodity				52,187	19,474	9,288	23,425
7								
8	Totals				1,720,172	952,765	422,400	345,007
9								
10	UNAMORTIZED RATE CASE EXPENSE							
11								
12	Unamortized Rate Case Expense							
13	Customer			A-20	76,170	59,532	10,104	6,534
14	Demand			A-21	26,502	13,558	7,274	5,670
15	Commodity			A-22	22,328	8,332	3,974	10,022
16								
17	Totals		C-8		125,000	81,422	21,352	22,226
18								
19	ACCUMULATED DEFERRED INCOME TAXES							
20								
21	Accumulated Deferred Income Taxes, ITC	253,282						
22	Customer	190		A-11	(249,385)	(190,213)	(33,432)	(25,740)
23	Demand			A-12	(332,386)	(170,048)	(91,231)	(71,107)
24	Commodity			A-13	(40,879)	(15,255)	(7,275)	(18,349)
25								
26	Totals		C-7		(622,650)	(375,516)	(131,938)	(115,196)
27								
28								
29	TOTAL RATE BASE							
30	Customer				14,464,581	11,033,978	1,938,989	1,491,614
31	Demand				20,128,946	10,297,935	5,524,837	4,306,174
32	Commodity				2,380,832	888,435	423,722	1,068,675
33								
34	Totals				36,974,359	22,220,348	7,887,548	6,866,463

NorthWestern Public Service
Class Cost of Service Study
Rate Base Calculation
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	RATE BASE SUMMARY							
2								
3	Customer Rate Base							
4								
5	Gas Plant in Service				20,442,359	15,591,992	2,740,466	2,109,931
6	Accumulated Reserve for Depreciation				(6,122,936)	(4,670,135)	(820,830)	(631,971)
7	Working Capital / Unamortized Rate Case Expense				394,543	302,364	52,785	39,394
8	Accumulated Deferred Income Taxes				(249,385)	(190,213)	(33,432)	(25,740)
9								
10	Total				14,464,581	11,033,978	1,938,989	1,491,614
11								
12								
13	Demand Rate Base							
14								
15	Gas Plant in Service				27,245,992	13,939,004	7,478,269	5,828,719
16	Accumulated Reserve for Depreciation				(8,160,774)	(4,175,038)	(2,239,906)	(1,745,830)
17	Working Capital / Unamortized Rate Case Expense				1,376,114	704,017	377,705	294,392
18	Accumulated Deferred Income Taxes				(332,386)	(170,048)	(91,231)	(71,107)
19								
20	Total				20,128,946	10,297,935	5,524,837	4,306,174
21								
22								
23	Commodity Rate Base							
24								
25	Gas Plant in Service				3,350,850	1,250,410	596,357	1,504,083
26	Accumulated Reserve for Depreciation				(1,003,654)	(374,526)	(178,622)	(450,506)
27	Working Capital / Unamortized Rate Case Expense				74,515	27,806	13,262	33,447
28	Accumulated Deferred Income Taxes				(40,879)	(15,255)	(7,275)	(18,349)
29								
30	Total				2,380,832	888,435	423,722	1,068,675
31								
32								
33	Total Rate Base							
34								
35	Gas Plant in Service				51,039,201	30,781,376	10,815,092	9,442,733
36	Accumulated Reserve for Depreciation				(15,287,364)	(9,219,699)	(3,239,358)	(2,828,307)
37	Working Capital / Unamortized Rate Case Expense				1,845,172	1,034,187	443,752	367,233
38	Accumulated Deferred Income Taxes				(622,650)	(375,516)	(131,938)	(115,196)
39								
40	Total				36,974,359	22,220,348	7,887,548	6,866,463

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Gas Production Operations							
4								
5	Supervision and engineering-labor	710						
6	Customer				0	0	0	0
7	Demand			A-2	12,137	6,210	3,331	2,596
8	Commodity				0	0	0	0
9								
10	Totals		C-2		12,137	6,210	3,331	2,596
11								
12	Supervision and engineering-other	710						
13	Customer				0	0	0	0
14	Demand			A-2	1,410	721	387	302
15	Commodity				0	0	0	0
16								
17	Totals		C-2		1,410	721	387	302
18								
19	Miscellaneous, fuel and LP gas expense-labor	717/735						
20	Customer	723			0	0	0	0
21	Demand			A-2	1,340	685	368	287
22	Commodity				0	0	0	0
23								
24	Totals		C-2		1,340	685	368	287
25								
26	Miscellaneous, fuel and LP gas expense-other	717/735						
27	Customer	723			0	0	0	0
28	Demand			A-2	3,760	1,924	1,032	804
29	Commodity				0	0	0	0
30								
31	Totals		C-2		3,760	1,924	1,032	804
32								
33	Gas Production Maintenance							
34								
35	Supervision and engineering-labor	740						
36	Customer				0	0	0	0
37	Demand			A-2	9,138	4,675	2,508	1,955
38	Commodity				0	0	0	0
39								
40	Totals		C-2		9,138	4,675	2,508	1,955
41								
42	Supervision and engineering-other	740						
43	Customer				0	0	0	0
44	Demand			A-2	1,121	573	308	240
45	Commodity				0	0	0	0
46								
47	Totals		C-2		1,121	573	308	240

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Gas Production Maintenance							
4								
5	Structures and production equipment-labor	741/742			0	0	0	0
6	Customer			A-2	2,237	1,144	614	479
7	Demand				0	0	0	0
8	Commodity							
9								
10	Totals		C-2		2,237	1,144	614	479
11								
12	Structures and production equipment-other	741/742			0	0	0	0
13	Customer			A-2	1,479	757	406	316
14	Demand				0	0	0	0
15	Commodity							
16								
17	Totals		C-2		1,479	757	406	316
18								
19	Total Production Expenses				0	0	0	0
20	Customer				32,622	16,689	8,954	6,979
21	Demand				0	0	0	0
22	Commodity							
23								
24	Totals				32,622	16,689	8,954	6,979
25								
26								
27								
28								
29								
30	Distribution Operation Expenses							
31								
32	Supervision and engineering-labor	870						
33	Customer			A-23	94,692	59,389	13,994	21,309
34	Demand			A-24	39,767	20,345	10,915	8,507
35	Commodity			A-25	65,466	24,430	11,651	29,385
36								
37	Totals		C-9		199,925	104,164	36,560	59,201
38								
39	Supervision and engineering-other	870						
40	Customer			A-23	112,150	70,338	16,574	25,238
41	Demand			A-24	47,099	24,096	12,927	10,076
42	Commodity			A-25	77,536	28,934	13,799	34,803
43								
44	Totals		C-9		236,786	123,368	43,300	70,117

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Operations Expenses							
4								
5	Distribution load dispatching-labor	871						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	73,836	27,553	13,141	33,142
9								
10	Totals		C-3		73,836	27,553	13,141	33,142
11								
12	Distribution load dispatching-other	871						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	41,409	15,452	7,370	18,587
16								
17	Totals		C-3		41,409	15,452	7,370	18,587
18								
19	Compressor sta. labor and expenses-labor	872						
20	Customer				0	0	0	0
21	Demand			A-2	0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-2		0	0	0	0
25								
26	Compressor sta. labor and expenses-other	872						
27	Customer				0	0	0	0
28	Demand			A-2	0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-2		0	0	0	0
32								
33	Compressor station fuel and power	873						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	0	0	0	0
37								
38	Totals		C-3		0	0	0	0
39								
40	Mains and services expenses-labor	874						
41	Customer			A-14	46,497	38,404	5,642	2,451
42	Demand			A-15	100,609	51,472	27,614	21,523
43	Commodity			A-16	5,295	1,976	942	2,377
44								
45	Totals		C-5		152,401	91,852	34,198	26,351

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NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Operations Expenses							
4								
5	Mains and services expenses-other	874						
6	Customer			A-14	83,641	69,084	10,148	4,409
7	Demand			A-15	180,982	92,590	49,675	38,717
8	Commodity			A-16	9,525	3,555	1,695	4,275
9								
10	Totals		C-5		274,148	165,229	61,518	47,401
11								
12	Meas. and reg. station exp.(gen)-labor	875						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	13,311	4,967	2,369	5,975
16								
17	Totals		C-3		13,311	4,967	2,369	5,975
18								
19	Meas. and reg. station exp.(gen)-other	875						
20	Customer				0	0	0	0
21	Demand				0	0	0	0
22	Commodity			A-3	2,595	968	462	1,165
23								
24	Totals		C-3		2,595	968	462	1,165
25								
26	Meas. and reg. station exp.(indust)-labor	876						
27	Customer				0	0	0	0
28	Demand				0	0	0	0
29	Commodity			A-3	0	0	0	0
30								
31	Totals		C-3		0	0	0	0
32								
33	Meas. and reg station exp.(indust)-other	876						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	0	0	0	0
37								
38	Totals		C-3		0	0	0	0
39								
40	Meas. and reg. station exp.(c gate)-labor	877						
41	Customer				0	0	0	0
42	Demand				0	0	0	0
43	Commodity			A-3	35,369	13,198	6,295	15,876
44								
45	Totals		C-3		35,369	13,198	6,295	15,876

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NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description (a)	Account No. (b)	Classification Basis (c)	Allocation Basis (d)	Total Service Area (e)	Residential (f)	Small Commercial (g)	Large Commercial (h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Operations Expenses							
4								
5	Meas. and reg. station exp.(c gate)-other	877						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	8,509	3,176	1,514	3,819
9								
10	Totals		C-3		8,509	3,176	1,514	3,819
11								
12	Meter and house regulator expenses-labor	878						
13	Customer			A-4	266,989	179,634	39,585	47,770
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals		C-1		266,989	179,634	39,585	47,770
18								
19	Meter and house regulator expenses-other	878						
20	Customer			A-4	(8,901)	(5,988)	(1,320)	(1,593)
21	Demand				0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-1		(8,901)	(5,988)	(1,320)	(1,593)
25								
26	Customer installations expenses-labor	879						
27	Customer			A-1	46,945	40,556	5,958	431
28	Demand				0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-1		46,945	40,556	5,958	431
32								
33	Customer installations expenses-other	879						
34	Customer			A-1	(205,985)	(177,949)	(26,143)	(1,893)
35	Demand				0	0	0	0
36	Commodity				0	0	0	0
37								
38	Totals		C-1		(205,985)	(177,949)	(26,143)	(1,893)
39								
40	Other expenses-labor	880						
41	Customer				0	0	0	0
42	Demand				0	0	0	0
43	Commodity			A-3	228,011	85,085	40,580	102,346
44								
45	Totals		C-3		228,011	85,085	40,580	102,346

NorthWestern Public Service
Class Cost of Service Study
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South Dakota Gas
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Operations Expenses							
4								
5	Other expenses-other	880						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	34,278	12,791	6,101	15,386
9								
10	Totals		C-3		34,278	12,791	6,101	15,386
11								
12	Rents.	881						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	4,501	1,680	801	2,020
16								
17	Totals		C-3		4,501	1,680	801	2,020
18								
19	Total Distribution Operations Expenses							
20	Customer				436,028	273,468	64,438	98,122
21	Demand				368,457	188,503	101,131	78,823
22	Commodity				599,641	223,765	106,720	269,156
23								
24	Totals				1,404,126	685,736	272,289	446,101
25								
26								
27								
28								
29								
30	Distribution Maintenance Expenses							
31								
32	Supervision and engineering-labor	885						
33	Customer			A-26	38,465	27,808	5,364	5,293
34	Demand			A-27	9,886	5,058	2,713	2,115
35	Commodity			A-28	10,634	3,969	1,892	4,773
36								
37	Totals		C-10		58,985	36,835	9,969	12,181
38								
39	Supervision and engineering-other	885						
40	Customer			A-26	2,062	1,490	288	284
41	Demand			A-27	530	272	145	113
42	Commodity			A-28	570	213	101	256
43								
44	Totals		C-10		3,162	1,975	534	653

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NorthWestern Public Service
Class Cost of Service Study
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South Dakota Gas
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Maintenance Expenses							
4								
5	Structures and improvements-labor	886			0	0	0	0
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3				
9								
10	Totals		C-3		0	0	0	0
11								
12	Structures and improvements-other	886			0	0	0	0
13	Customer				0	0	0	0
14	Demand				90	34	16	40
15	Commodity			A-3				
16								
17	Totals		C-3		90	34	16	40
18								
19	Mains-labor	887						
20	Customer			A-6	0	0	0	0
21	Demand			A-2	21,886	11,197	6,007	4,682
22	Commodity			A-3	1,152	430	205	517
23								
24	Totals		C-4		23,038	11,627	6,212	5,199
25								
26	Mains-other	887						
27	Customer			A-6	0	0	0	0
28	Demand			A-2	9,648	4,936	2,648	2,064
29	Commodity			A-3	508	190	90	228
30								
31	Totals		C-4		10,158	5,126	2,738	2,292
32								
33	Compressor station equipment-labor	888			0	0	0	0
34	Customer				0	0	0	0
35	Demand			A-2	0	0	0	0
36	Commodity							
37								
38	Totals		C-2		0	0	0	0
39								
40	Compressor station equipment-other	888			0	0	0	0
41	Customer				0	0	0	0
42	Demand			A-2	0	0	0	0
43	Commodity							
44								
45	Totals		C-2		0	0	0	0

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Maintenance Expenses							
4								
5	Meas. and reg. station equip.(gen)-labor	889						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	11,850	4,422	2,109	5,319
9								
10	Totals		C-3		11,850	4,422	2,109	5,319
11								
12	Meas. and reg. station equip.(gen)-other	889						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	647	242	115	290
16								
17	Totals		C-3		647	242	115	290
18								
19	Meas. and reg station exp.(indust)-labor	890						
20	Customer				0	0	0	0
21	Demand				0	0	0	0
22	Commodity			A-3	0	0	0	0
23								
24	Totals		C-3		0	0	0	0
25								
26	Meas. and reg. station exp.(indust)-other	890						
27	Customer				0	0	0	0
28	Demand				0	0	0	0
29	Commodity			A-3	0	0	0	0
30								
31	Totals		C-3		0	0	0	0
32								
33	Meas. and reg. station exp.(c gate)-labor	891						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	1,492	556	266	670
37								
38	Totals		C-3		1,492	556	266	670
39								
40	Meas. and reg. station exp.(c gate)-other	891						
41	Customer				0	0	0	0
42	Demand				0	0	0	0
43	Commodity			A-3	264	98	47	119
44								
45	Totals		C-3		264	98	47	119

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Maintenance Expenses							
4								
5	Services-labor	892						
6	Customer			A-6	31,159	25,735	3,781	1,643
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals		C-1		31,159	25,735	3,781	1,643
11								
12	Services-other	892						
13	Customer			A-6	9,956	8,223	1,208	525
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals		C-1		9,956	8,223	1,208	525
18								
19	Meters and house regulators-labor	893						
20	Customer			A-4	74,015	49,798	10,974	13,243
21	Demand				0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-1		74,015	49,798	10,974	13,243
25								
26	Meters and house regulators-other	893						
27	Customer			A-4	10,421	7,011	1,545	1,865
28	Demand				0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-1		10,421	7,011	1,545	1,865
32								
33	Other equipment-labor	894						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	0	0	0	0
37								
38	Totals		C-3		0	0	0	0
39								
40	Other equipment-other	894						
41	Customer				0	0	0	0
42	Demand				0	0	0	0
43	Commodity			A-3	0	0	0	0
44								
45	Totals		C-3		0	0	0	0

NorthWestern Public Service
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South Dakota Gas
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Maintenance Expenses							
4								
5	Total Distribution Maintenance Expenses							
6	Customer				166,078	120,065	23,160	22,853
7	Demand				41,850	21,463	11,513	8,974
8	Commodity				27,207	10,154	4,841	12,212
9								
10	Totals				235,235	151,682	39,514	44,039
11								
12	Total Distribution O. & M. Expenses							
13	Customer				602,106	393,533	87,598	120,975
14	Demand				410,407	209,966	112,644	87,797
15	Commodity				626,848	233,919	111,561	281,368
16								
17	Totals				1,639,361	837,418	311,803	490,140
18								
19								
20								
21								
22								
23	Customer Accounts Expenses							
24								
25	Supervision-labor	901						
26	Customer			A-7	172,822	146,605	21,538	4,679
27	Demand				0	0	0	0
28	Commodity				0	0	0	0
29								
30	Totals		C-1		172,822	146,605	21,538	4,679
31								
32	Supervision-other	901						
33	Customer			A-7	(18,765)	(15,916)	(2,339)	(508)
34	Demand				0	0	0	0
35	Commodity				0	0	0	0
36								
37	Totals		C-1		(18,765)	(15,916)	(2,339)	(508)

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Customer Accounts Expenses							
4								
5	Meter reading expenses-labor	902						
6	Customer			A-7	229,997	195,108	28,663	6,226
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals		C-1		229,997	195,108	28,663	6,226
11								
12	Meter reading expenses-other	902						
13	Customer			A-7	29,495	25,021	3,676	798
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals		C-1		29,495	25,021	3,676	798
18								
19	Customer records & collection exp.-labor	903						
20	Customer			A-7	292,413	248,055	36,442	7,916
21	Demand				0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-1		292,413	248,055	36,442	7,916
25								
26	Customer records & collection exp.-other	903						
27	Customer			A-7	141,178	119,762	17,594	3,822
28	Demand				0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-1		141,178	119,762	17,594	3,822
32								
33	Uncollectible accounts	904						
34	Customer			A-7	88,594	75,155	11,041	2,398
35	Demand				0	0	0	0
36	Commodity				0	0	0	0
37								
38	Totals		C-1		88,594	75,155	11,041	2,398
39								
40	Misc. customer accounts expenses-labor	905						
41	Customer			A-7	14	12	2	0
42	Demand				0	0	0	0
43	Commodity				0	0	0	0
44								
45	Totals		C-1		14	12	2	0

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Customer Accounts Expenses							
4								
5	Misc. customer accounts expenses-other	905						
6	Customer			A-7	15,419	13,080	1,922	417
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals		C-1		15,419	13,080	1,922	417
11								
12	Total Customer Accounts Expenses							
13	Customer				951,167	806,880	118,539	25,748
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals				951,167	806,880	118,539	25,748
18								
19								
20								
21								
22								
23	Customer Service & Information Expenses							
24								
25	Supervision-labor	907						
26	Customer			A-7	7,166	6,079	893	194
27	Demand				0	0	0	0
28	Commodity				0	0	0	0
29								
30	Totals		C-1		7,166	6,079	893	194
31								
32	Supervision-other	907						
33	Customer			A-7	0	0	0	0
34	Demand				0	0	0	0
35	Commodity				0	0	0	0
36								
37	Totals		C-1		0	0	0	0
38								
39	Customer assistance expense-labor	908						
40	Customer			A-7	60,249	51,109	7,509	1,631
41	Demand				0	0	0	0
42	Commodity				0	0	0	0
43								
44	Totals		C-1		60,249	51,109	7,509	1,631

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NorthWestern Public Service
Class Cost of Service Study
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South Dakota Gas
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Customer Service & Information Expenses							
4								
5	Customer assistance expense-other	908						
6	Customer			A-7	706,838	599,613	88,090	19,135
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals		C-1		706,838	599,613	88,090	19,135
11								
12	Inform. & instr. advertising exp.-labor	909						
13	Customer			A-7	13,697	11,619	1,707	371
14	Demand				0	0	0	0
15	Commodity				0	0	0	0
16								
17	Totals		C-1		13,697	11,619	1,707	371
18								
19	Inform. & instr. advertising exp.-other	909						
20	Customer			A-7	9,973	8,460	1,243	270
21	Demand				0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-1		9,973	8,460	1,243	270
25								
26	Misc. customer service & inform.-labor	910						
27	Customer			A-7	10,636	9,022	1,326	288
28	Demand				0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-1		10,636	9,022	1,326	288
32								
33	Misc. customer service & inform.-other	910						
34	Customer			A-7	4,859	4,121	606	132
35	Demand				0	0	0	0
36	Commodity				0	0	0	0
37								
38	Totals		C-1		4,859	4,121	606	132

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NorthWestern Public Service
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Line No.	Description (a)	Account No. (b)	Classification Basis (c)	Allocation Basis (d)	Total Service Area (e)	Residential (f)	Small Commercial (g)	Large Commercial (h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Customer Service & Information Expenses							
4								
5	Total Customer Service & Information Exp.							
6	Customer				813,418	690,023	101,374	22,021
7	Demand				0	0	0	0
8	Commodity				0	0	0	0
9								
10	Totals				813,418	690,023	101,374	22,021
11								
12								
13								
14								
15								
16	Sales Expenses							
17								
18	Supervision-labor	911						
19	Customer				0	0	0	0
20	Demand				0	0	0	0
21	Commodity			A-3	0	0	0	0
22								
23	Totals		C-3		0	0	0	0
24								
25	Supervision-other	911						
26	Customer				0	0	0	0
27	Demand				0	0	0	0
28	Commodity			A-3	0	0	0	0
29								
30	Totals		C-3		0	0	0	0
31								
32	Demonstrating and selling-labor	912						
33	Customer				0	0	0	0
34	Demand				0	0	0	0
35	Commodity			A-3	0	0	0	0
36								
37	Totals		C-3		0	0	0	0
38								
39	Demonstrating and selling-other	912						
40	Customer				0	0	0	0
41	Demand				0	0	0	0
42	Commodity			A-3	0	0	0	0
43								
44	Totals		C-3		0	0	0	0

NorthWestern Public Service
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Sales Expenses							
4								
5	Advertising-labor	913						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	0	0	0	0
9								
10	Totals		C-3		0	0	0	0
11								
12	Advertising-other	913						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	0	0	0	0
16								
17	Totals		C-3		0	0	0	0
18								
19	Misc. sales expense-labor	916						
20	Customer				0	0	0	0
21	Demand				0	0	0	0
22	Commodity			A-3	0	0	0	0
23								
24	Totals		C-3		0	0	0	0
25								
26	Misc. sales expense-other	916						
27	Customer				0	0	0	0
28	Demand				0	0	0	0
29	Commodity			A-3	0	0	0	0
30								
31	Totals		C-3		0	0	0	0
32								
33	Total Sales Expenses							
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity				0	0	0	0
37								
38	Totals				0	0	0	0

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NorthWestern Public Service
Class Cost of Service Study
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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Administrative and General Expenses							
4								
5	Administrative and general salaries	920						
6	Customer			A-17	551,588	433,440	72,992	45,156
7	Demand			A-18	69,948	35,784	19,198	14,964
8	Commodity			A-19	177,692	66,308	31,624	79,760
9								
10	Totals		C-6		799,226	535,532	123,814	139,880
11								
12	Office supplies and expenses	921						
13	Customer			A-17	362,925	285,168	48,026	29,711
14	Demand			A-18	46,022	23,544	12,632	9,846
15	Commodity			A-19	116,915	43,628	20,808	52,479
16								
17	Totals		C-6		525,862	352,360	81,466	92,036
18								
19	Administrative expenses transferred-labor	922						
20	Customer			A-17	0	0	0	0
21	Demand			A-18	0	0	0	0
22	Commodity			A-19	0	0	0	0
23								
24	Totals		C-6		0	0	0	0
25								
26	Administrative expenses transferred-other	922						
27	Customer			A-17	(522,019)	(410,205)	(69,079)	(42,735)
28	Demand			A-18	(66,196)	(33,866)	(18,169)	(14,161)
29	Commodity			A-19	(168,167)	(62,754)	(29,929)	(75,484)
30								
31	Totals		C-6		(756,382)	(506,825)	(117,177)	(132,380)
32								
33	Outside services employed	923						
34	Customer			A-20	139,218	108,809	18,467	11,942
35	Demand			A-21	48,439	24,781	13,295	10,363
36	Commodity			A-22	40,809	15,228	7,263	18,318
37								
38	Totals		C-6		228,466	148,818	39,025	40,623
39								
40	Workmen's compensation insurance	924						
41	Customer			A-17	0	0	0	0
42	Demand			A-18	0	0	0	0
43	Commodity			A-19	0	0	0	0
44								
45	Totals		C-6		0	0	0	0

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Administrative and General Expenses							
4								
5	Property Insurance	924						
6	Customer			A-11	9,144	6,974	1,226	944
7	Demand			A-12	12,187	6,235	3,345	2,607
8	Commodity			A-13	1,499	559	267	673
9								
10	Totals		C-7		22,830	13,768	4,838	4,224
11								
12	Injuries and damages	925						
13	Customer			A-17	57,132	44,895	7,560	4,677
14	Demand			A-18	7,245	3,706	1,989	1,550
15	Commodity			A-19	18,405	6,868	3,276	8,261
16								
17	Totals		C-6		82,782	55,469	12,825	14,488
18								
19	Employee pensions and benefits-labor	926						
20	Customer			A-17	26,890	21,131	3,558	2,201
21	Demand			A-18	3,410	1,744	936	730
22	Commodity			A-19	8,663	3,232	1,542	3,889
23								
24	Totals		C-6		38,963	26,107	6,036	6,820
25								
26	Employee pensions and benefits-other	926						
27	Customer			A-17	436,244	342,803	57,728	35,713
28	Demand			A-18	55,319	28,302	15,183	11,834
29	Commodity			A-19	140,534	52,442	25,011	63,081
30								
31	Totals		C-6		632,097	423,547	97,922	110,628
32								
33	Regulatory commission expenses	928						
34	Customer			A-20	30,468	23,813	4,041	2,614
35	Demand			A-21	10,601	5,423	2,910	2,268
36	Commodity			A-22	8,931	3,332	1,590	4,009
37								
38	Totals		C-8		50,000	32,568	8,541	8,891
39								
40	Miscellaneous general expenses-labor	930						
41	Customer			A-20	5,273	4,122	699	452
42	Demand			A-21	1,835	938	504	393
43	Commodity			A-22	1,545	576	275	694
44								
45	Totals		C-8		8,653	5,636	1,478	1,539

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Administrative and General Expenses							
4								
5	Miscellaneous general expenses-other	930						
6	Customer			A-20	108,620	84,895	14,408	9,317
7	Demand			A-21	37,793	19,335	10,373	8,085
8	Commodity			A-22	31,840	11,881	5,667	14,292
9								
10	Totals		C-8		178,253	116,111	30,448	31,694
11								
12	Rents	931						
13	Customer			A-11	94,672	72,209	12,692	9,771
14	Demand			A-12	126,181	64,554	34,633	26,994
15	Commodity			A-13	15,518	5,790	2,762	6,966
16								
17	Totals		C-7		236,371	142,553	50,087	43,731
18								
19	Maintenance of buildings-labor	932						
20	Customer			A-11	8,904	6,791	1,194	919
21	Demand			A-12	11,867	6,071	3,257	2,539
22	Commodity			A-13	1,460	545	260	655
23								
24	Totals		C-7		22,231	13,407	4,711	4,113
25								
26	Maintenance of buildings-other	932						
27	Customer			A-11	92,214	70,334	12,362	9,518
28	Demand			A-12	122,904	62,877	33,734	26,293
29	Commodity			A-13	15,115	5,640	2,690	6,785
30								
31	Totals		C-7		230,233	138,851	48,786	42,596
32								
33	Total Administrative and General Expenses							
34	Excluding Rate Case Expenses							
35	Customer				1,370,805	1,071,388	181,833	117,586
36	Demand				476,952	244,005	130,910	102,037
37	Commodity				401,828	149,943	71,516	180,369
38								
39	Totals				2,249,585	1,465,334	384,259	399,992
40								
41	Total Operations and Maintenance Expenses							
42	Excluding Gas Cost							
43	Customer				3,737,496	2,961,822	489,344	286,330
44	Demand				919,981	470,660	252,508	196,813
45	Commodity				1,028,676	383,862	183,077	461,737
46								
47	Totals				5,686,153	3,816,344	924,929	944,880

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	DEPRECIATION & AMORTIZATION EXPENSE							
2								
3	Distribution and Production Plant	403						
4	Customer			A-11	493,622	376,499	66,174	50,949
5	Demand			A-12	657,910	336,586	180,578	140,746
6	Commodity			A-13	80,913	30,194	14,400	36,319
7								
8	Totals		C-7		1,232,445	743,279	261,152	228,014
9								
10	General Plant	403						
11	Customer			A-11	153,777	117,290	20,615	15,872
12	Demand			A-12	204,958	104,856	56,255	43,847
13	Commodity			A-13	25,207	9,406	4,486	11,315
14								
15	Totals		C-7		383,942	231,552	81,356	71,034
16								
17	Intangible Plant and Other	404,406						
18	Customer			A-11	161	122	22	17
19	Demand			A-12	215	110	59	46
20	Commodity			A-13	27	10	5	12
21								
22	Totals		C-7		403	242	86	75
23								
24	Total Depreciation & Amortization Expense							
25	Customer				647,560	493,911	86,811	66,838
26	Demand				863,083	441,552	236,892	184,639
27	Commodity				106,147	39,610	18,891	47,646
28								
29	Totals				1,616,790	975,073	342,594	299,123

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Line No.	Description	Account No.	Classification Basis	Allocation Basis	Total Service Area	Residential	Small Commercial	Large Commercial
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	PAYROLL COSTS OTHER THAN ADMIN. & GENERAL							
2								
3	Gas Production Expenses	710-742						
4	Customer				0	0	0	0
5	Demand				3,577	1,829	982	766
6	Commodity				0	0	0	0
7								
8	Totals				3,577	1,829	982	766
9								
10	Distribution Operations & Maintenance	870-894						
11	Customer				598,762	421,324	85,298	92,140
12	Demand				172,148	88,072	47,249	36,827
13	Commodity				446,416	166,586	79,450	200,380
14								
15	Totals				1,217,326	675,982	211,997	329,347
16								
17	Customer Accounts Expenses							
18	Customer	901-905			695,246	589,780	86,645	18,821
19	Demand				0	0	0	0
20	Commodity				0	0	0	0
21								
22	Totals				695,246	589,780	86,645	18,821
23								
24	Customer Service & Information Expenses	907-910						
25	Customer				91,748	77,829	11,435	2,484
26	Demand				0	0	0	0
27	Commodity				0	0	0	0
28								
29	Totals				91,748	77,829	11,435	2,484
30								
31	Sales Expenses	911-916						
32	Customer				0	0	0	0
33	Demand				0	0	0	0
34	Commodity				0	0	0	0
35								
36	Totals				0	0	0	0
37								
38	Total Payroll Costs							
39	Customer				1,385,756	1,088,933	183,378	113,445
40	Demand				175,725	89,901	48,231	37,593
41	Commodity				446,416	166,586	79,450	200,380
42								
43	Totals				2,007,897	1,345,420	311,059	351,418

NorthWestern Public Service
Class Cost of Service Study
Expenses
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description (a)	Account No. (b)	Classification Basis (c)	Allocation Basis (d)	Total Service Area (e)	Residential (f)	Small Commercial (g)	Large Commercial (h)
1	OPERATIONS & MAINTENANCE EXPENSES							
2								
3	Distribution Operations Expenses							
4								
5	Distribution load dispatching-labor	871						
6	Customer				0	0	0	0
7	Demand				0	0	0	0
8	Commodity			A-3	73,836	27,553	13,141	33,142
9								
10	Totals		C-3		73,836	27,553	13,141	33,142
11								
12	Distribution load dispatching-other	871						
13	Customer				0	0	0	0
14	Demand				0	0	0	0
15	Commodity			A-3	41,409	15,452	7,370	18,587
16								
17	Totals		C-3		41,409	15,452	7,370	18,587
18								
19	Compressor sta. labor and expenses-labor	872						
20	Customer				0	0	0	0
21	Demand			A-2	0	0	0	0
22	Commodity				0	0	0	0
23								
24	Totals		C-2		0	0	0	0
25								
26	Compressor sta. labor and expenses-other	872						
27	Customer				0	0	0	0
28	Demand			A-2	0	0	0	0
29	Commodity				0	0	0	0
30								
31	Totals		C-2		0	0	0	0
32								
33	Compressor station fuel and power	873						
34	Customer				0	0	0	0
35	Demand				0	0	0	0
36	Commodity			A-3	0	0	0	0
37								
38	Totals		C-3		0	0	0	0
39								
40	Mains and services expenses-labor	874						
41	Customer			A-14	46,497	38,404	5,642	2,451
42	Demand			A-15	100,609	51,472	27,614	21,523
43	Commodity			A-16	5,295	1,976	942	2,377
44								
45	Totals		C-5		152,401	91,852	34,198	26,351

South Dakota Public Utilities Commission

WEEKLY FILINGS

For the Period of May 27, 1999 through June 2, 1999

If you need a complete copy of a filing faxed, overnight expressed, or mailed to you, please contact Delaine Kolbo within five business days of this filing.
Phone: 605-773-3705 Fax: 605-773-3809

CONSUMER COMPLAINT

CT99-005 In the Matter of the Complaint filed by Nancy Manning and Elizabeth Frederick, Rapid City, South Dakota, against U S WEST Communications, Inc. and McLeodUSA Telecommunications Services, Inc. Regarding the Inability to Provide Service

On May 27, 1999, the Commission received a complaint from Nancy Manning and Elizabeth Frederick, Rapid City, South Dakota, against U S West Communications, Inc. and McLeodUSA Telecommunications Services, Inc. regarding the inability to provide service. The complainants are asking for immediate phone service, reimbursement for expenses, reimbursement for loss of business, an independent contractor allowed to enter USWC, and an explanation concerning discriminatory treatment.

Consumer Affairs: Leni Healy
Legal Intern: Jeff Koerselman
Date Filed: 05/27/99

ELECTRIC

EL99-011 In the Matter of the Filing by Montana-Dakota Utilities Co. for Approval of Revised Power Purchase Tariffs Rates 95, 96 and 97

Application by Montana-Dakota Utilities Company to revise power purchase rate schedules 95, 96 and 97 in compliance with the Commission's Order in Docket F-3365 which dictated annual review and if necessary, revision of these rates based on updated information. The rates filed apply to the purchase of power from cogeneration or small power production facilities of customers. No customers are currently served by these rates in South Dakota.

Staff Analyst: Dave Jacobson
Staff Attorney: Camron Hoseck
Date Filed: 06/01/99
Intervention Deadline: NA

GAS AND ELECTRIC

GE99-004 In the Matter of the Filing by Northwestern Public Service for Approval of Revised Customer Information Handbook

On June 1, 1999, Northwestern Public Service filed a docket requesting review and approval pursuant to Administrative Rule 20:10:16:02 for their new Customer Handbook.

Staff Analyst: Michele Farris
Staff Attorney: Karen Cremer
Date Filed: 06/01/99
Intervention Date: 06/18/99

NATURAL GAS

NG99-002 In the Matter of the Application of Northwestern Public Service for Authority to Increase Rates for Natural Gas Service

On June 1, 1999, the Commission received an application from NorthWestern Public Service, a division of Northwestern Corporation, for an increase in rates for natural gas service in South Dakota. The Company has requested that the proposed increase of $2,108,112 or approximately 6.3% become effective July 1, 1999.

Staff Analyst: Bob Knadle
Staff Attorney: Karen Cremer
Date Filed: 06/01/99
Intervention Deadline: To be determined by Commission Order

You may receive this listing and other PUC publications via our website or via internet e-mail. You may subscribe or unsubscribe to the PUC mailing lists at http://www.state.sd.us/puc/

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	ORDER OF ASSESSMENT OF FILING FEE, NOTICE OF OPPORTUNITY TO INTERVENE, AND SUSPENSION OF IMPOSITION OF TARIFF NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

SDCL 49-1A-8 authorizes the Commission to require a deposit of up to one hundred thousand dollars ($100,000) in the South Dakota Public Utilities Commission's (SDPUC) regulatory assessment fee fund to defray Commission expenses incident to analyzing and ruling upon this type of filing. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26, 49-1A, 49-34A and ARSD 20:10:01:15.02 and 20:10:01:15.03.

At its regularly scheduled meeting of June 22, 1999, the Commission considered this matter. The Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-31-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. It is therefore

ORDERED, that NWPS shall deposit a filing fee, to be established by the executive director, in the SDPUC regulatory assessment fee fund and it shall deposit any additional amounts as requested by the executive director, not to exceed the statutory limit; it is further

ORDERED, that any individual or entity may file with the Commission its petition to intervene no later than July 22, 1999; and it is further

ORDERED, that the proposed schedule of rates shall be suspended for 90 days beyond July 1, 1999, pursuant to SDCL 49-34A-14.

Dated at Pierre, South Dakota, this 25th day of June, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 6/25/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

JAMES A. BURG, Chairman

PAM NELSON, Commissioner

LASKA SCHOENFELDER, Commissioner

Dear Jim Burg - Jacka Schoenfelder
+ Ken Stofferahn —

I can not believe you
would even consider giving
NWPS another rate raise —
Every year they come to
you they need a new
plant (or something) They
get a raise - We pay for
it but they own it —
The rates are so high now
we can hardly afford to
live in our houses —
Please compare our rates
to Pierre, Watertown, Brookings
Yankton or any other town
our size + you will find

our rates are much higher than any one else - They use to be a wonderful Co. but things have changed - Where do you think they got the money for these wonderful investments. If we had a choice I don't think we would choose NWPS -

Yours truly

Mary Franey

223 W 4

Mitchell, SD

57301

Deal to let AT&T offer Net, phone over cable

The Associated Press

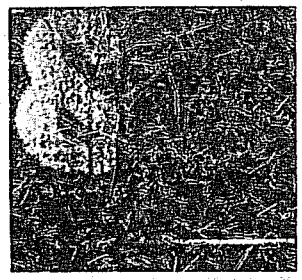
NEW YORK – AT&T has emerged triumphant in the high-stakes fight for one of the nation's largest cable companies, forging a deal that will give it access to 60 percent of American homes with cable.

The agreement reached late Tuesday between AT&T and Comcast Corp. averts a bidding war for MediaOne Group Inc. It allows AT&T to complete its $54 billion acquisition of the Denver-based cable TV company.

AT&T plans to use cable systems to deliver local and long-distance phone service, high-speed Internet access and interactive entertainment to millions of U.S. homes.

AT&T has been moving rapidly into the cable business, buying No. 2 cable company Tele-Communications Inc. last year and more recently snapping up smaller cable systems and signing affiliation agreements with others.

AT&T will exchange various cable systems with Comcast in swaps that could result in Comcast gaining an additional 2 million subscribers and AT&T receiving up to $9.2 billion. Most of the exchanges are contingent on AT&T acquiring MediaOne.



Associated Press file photo

AT&T Chairman Michael Armstrong addresses a special shareholders meeting on Feb. 17 in Secaucus, N.J.

Shareholders in NorthWestern racking up profits as stocks soa

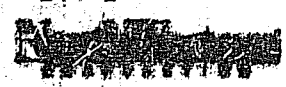
Firm has six years of record earnings

By MIKE TRAUTMANN
Argus Leader Staff

Leona and Lavern Klemb don't pretend to understand all of the corporate jargon and business sloganism that was slung at them and more than 300 other shareholders at NorthWestern Corp's annual meeting Wednesday.

But the rural Mitchell couple know what NorthWestern's success has meant to their corporate stock, and that alone is enough to make them grin in pleased delight.

"This is our emergency and retirement money," Leona Klemb said after leaving the upbeat meeting. "I'm 77 and my husband is 78. I suppose we should be using that money right now, but we're not."



NorthWestern's bottom line is making plenty of stockholders smile. The corporation has expanded beyond its roots as an electrical and natural-gas supplier into partnerships in heating and plumbing, propane sales and voice and data communication.

The Sioux Falls-based corporation's stock has split twice since 1988, and corporate officers confidently predict the stock price will double again within four years.

In other words, if you're looking to buy stock, you might want to take a peek at NorthWestern, says Jim Cink, an investment executive with Piper Jaffrey of Sioux Falls. NorthWestern's stock closed Wednesday at 25½, down ½.

"It's a well-diversified company," Cink says. "I think they've got potential for growth."

NorthWestern President Richard Hylland thinks the same. Five years ago, executives of the successful NorthWestern Public Service energy company took a gamble, expanding into service industries that complemented their own, Hylland said.

They partnered with Blue Dot, a heating, cooling and plumbing business; CornerStone Propane, one of the largest retail dealers in America; and Exp@nets, which provides voice and data communications.

"Now we have unlimited growth potential," Hylland said.

The diversification h
dividends. When b
back mild winters c
NorthWestern's natu
sales, the corporation
ner businesses helpec
up cash flow.

The result is six
years of record earnin
ping out at $1.2 billion
Common-stock e
have climbed from 88
share in 1992 to $1.
year.

That prosperity is
off for stockholders
David Trulson of Siou
Trulson first bought
Western stock in 1982
watched the return
climbing.

"My stock is wor
times as much," he sa
one of the better sto
had for all these year
if I just would have
more ... "

NWPS seeks boost in natural gas rate

PIERRE (AP) — Northwestern Public Service has filed a request to boost rates for natural gas by about 6.3 percent for its 38,670 customers in eastern South Dakota.

NWPS wanted to increase rates July 1, but the state Public Utilities Commission decided Tuesday to suspend the imposition of the increase for 90 days.

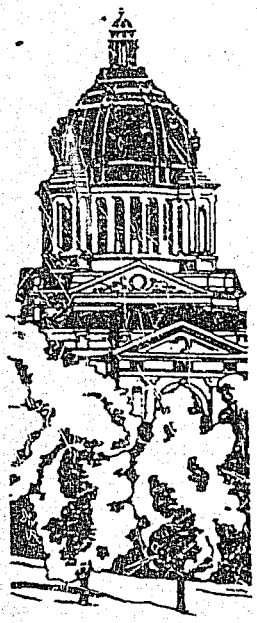
The commission also set July 22 as the deadline for anyone to intervene in the case.

The company's request seeks to boost revenue by more than $2.1 million, a 6.3 percent increase.

If approved by the PUC, the increase would add $3.20 a month to the average residential bill, NWPS said.

The company, based in Huron, said the requested increase would help it improve customer service and the reliability of its natural gas delivery system.

Bill Bullard, executive director of the PUC, said it usually takes six months for the PUC to issue a decision in such rate cases.



South Dakota Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

July 7, 1999

Mary Franey
223 W 4th
Mitchell SD 57301

Dear Ms. Franey:

We received your letter on July 1, 1999, regarding NWPS' proposed natural gas rate increase. NWPS filed for an increase on June 1, 1999. Our review will take several months, and a change in rates, if any, would not take place before this fall. We will make your letter part of the permanent record we shall review before making any decision. We thank you for your willingness to have your thoughts included in the record.

There were some issues raised in your letter, and I think some information regarding those issues may be helpful:

1. **"Every year they come to you they need a new plant (or something) they get a raise - we pay for it but they own it -. . ."**

NWPS's last rate increase was in 1994. The rate increase before that occurred in 1986. We recently approved bill format changes to make the billings easier to understand, but those changes did not result in rate increases. They merely changed the format of your service was billing.

The purchased gas adjustment (PGA), a line item on your bill, does change from time to time, but that only covers the *cost of gas* portion of the rate. Plants, salaries, pipe, insurance, office costs and any other *non-gas* expenses are not covered by the PGA. NWPS's rate increase request is for the *non-gas* costs.

Utilities are private businesses providing a commodity, in this case natural gas, and service. Ratepayers do indeed pay for service provided by the utility without receiving any ownership of the utility. This is also true of almost all other businesses such as grocery stores, Wal-Mart or McDonalds. Our concern is that what you are paying for that service is fair.

Capitol Office
Telephone (605)773-3201
FAX (605)773-3809

Transportation/
Warehouse Division
Telephone (605)773-5280
FAX (605)773-3225

Consumer Hotline
1-800-332-1782

TTY Through
Relay South Dakota
1-800-877-1113

Internet Website
www.puc.state.sd.us/puc/

Jim Burg
Chairman
Pam Nelson
Vice-Chairman
Laska Schoenfelder
Commissioner

William Bullard Jr.
Executive Director

Harlan Best
Martin C. Bettmann
Sue Cichos
Karen E. Cremer
Michele M. Farris
Marlette Fischbach
Shirleen Fugitt
Lewis Hammond
Leni Healy
Camron Hoseck
Lisa Hull
Dave Jacobson
Katie Johnson
Bob Knadle
Delaine Kolbo
Jeffrey P. Lorensen
Charlene Lund
Terry Norum
Gregory A. Rislov
Keith Senger
Rolayne Ailts Wiest

2. **"Please compare our rates. . . and you will find they are much higher than anyone else. . ."**

Below is a list of rates charged for natural gas service by the three largest investor-owned utilities operating in South Dakota. I have priced typical February usage of 158 therms.

MidAmerican (Sioux Falls,Yankton)	$70.16
NWPS*	**$84.28**
MDU (East River system, Pierre)	$97.85
MDU (Black Hills system)	$92.15

*Rate level prior to any rate increase.

It would be a coincidence if any two companies had identical rates. There are many reasons for company-by-company differences. For instance, it's not surprising that Sioux Falls has the lowest rate as: 1) there are many customers in a small area, and 2) among those there are many large customers. Both (1) and (2) lead to lower average costs per customer. It is not surprising that Pierre has the highest rate as there are relatively few customers and relatively few large users.

Further, even though Pierre's rates are the highest, MDU is not getting rich from this higher rate. I would speculate they are earning less on the Pierre system than any of the others are companies are earning as MDU's plant is quite new, the costs are therefore relatively high, and the customer base is still growing. As I stated before, there are many reasons why rates are not identical from company-to-company.

3. The newspaper article about Northwestern Corporation earning increased profits:

The article spoke to Northwestern Corporation as a whole. The article also mentioned deflated gas sales, which is an indication that earnings in the gas business are not the cause for Northwestern's increased earnings overall. We, by law, cannot consider profits earned in any other business when reviewing natural gas rates. The natural gas business is separated from other businesses. From a legal and therefore a regulatory point-of-view, it must stand by itself.

Is this good or bad? When other businesses are doing well and natural gas isn't, people would like to have the natural gas rates subsidized by other businesses. But consider the alternative, because it would have to work both ways. Would you want your natural gas rates to subsidize other businesses if the other businesses, which are not regulated, weren't doing well? There have been many instances where regulated utilities also had

unregulated companies that lost money. If it did work that way, you could end up paying for those losses. You would have paid for failed decisions that in no way would ever have any chance of directly benefitting you. You would be assuming an open-ended risk. It would be unfair. Nonutility risks and rewards should be the business of the stockholders or owners, not the ratepayers or customers.

We clearly understand that customers dislike paying rate increases. We dislike rate increases. A utility is not automatically allowed to increase rates to a level they would like. A utility must file specific, detailed data to support any rate increase request. That data is scrutinized, is often supplemented with more data, is thoroughly reviewed and challenged, and witnesses providing the calculations are subject to cross-examination based on reviews by other experts.

We know the South Dakota economy. We understand how many people are challenged to pay their bills. We realize that utilities provide for very basic needs. We want those needs to be affordable.

We appreciate the opportunity to explain the rate increase process. If you have additional questions or comment or want any clarification, feel free to contact us.

Sincerely,

Greg Rislov,
Commission Advisor

c: Laska Schoenfelder, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	ORDER FOR AND NOTICE OF HEARING NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 1-26-17.1, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21, and ARSD 20:10:01:15.02 and .03.

The procedural schedule for testimony shall be as follows:

DATE	PROCEDURAL SCHEDULE
September 24, 1999	Staff and Intervenors' Prefiled Testimony Due
October 8, 1999	Rebuttal Testimony Due

A hearing shall be held at 9:00 a.m., on Wednesday, October 20, 1999, and Thursday, October 21, 1999, in Room 412, State Capitol Building. 500 East Capitol, Pierre, South Dakota. The hearing is open to the public. All persons so testifying shall be subject to cross-examination.

The issue at the hearing is whether the Commission shall grant NWPS' request to implement revised natural gas rate schedules designed to produce additional revenues of $2,108,112.

The hearing shall be an adversary proceeding conducted pursuant to SDCL Chapter 1-26. All parties have the right to be present and to be represented by an attorney. These rights and other due process rights shall be forfeited if not exercised at

the hearing. If you or your representative fail to appear at the time and place set for the hearing, the Final Decision will be based solely on the testimony and evidence provided, if any, during the hearing or a Final Decision may be issued by default pursuant to SDCL 1-26-20. After the hearing the Commission will consider all evidence and testimony that was presented at the hearing. The Commission will then enter Findings of Fact, Conclusions of Law, and a Final Decision regarding this matter. As a result of this hearing, the Commission shall determine whether it shall grant NWPS' request to implement revised rate schedules. The Commission's Final Decision may be appealed by the parties to the state Circuit Court and the state Supreme Court as provided by law. It is therefore

ORDERED that the procedural schedule set forth above shall be followed by all parties to these proceedings. It is further

ORDERED that the hearing shall commence at 9:00 a.m., on Wednesday, October 20, 1999, in Room 412, State Capitol Building, 500 East Capitol, Pierre, South Dakota, and if necessary, shall continue through Thursday, October 21, 1999.

Pursuant to the Americans with Disabilities Act, this hearing is being held in a physically accessible location. Please contact the Public Utilities Commission at 1-800-332-1782 at least 48 hours prior to the hearing if you have special needs so arrangements can be made to accommodate you.

Dated at Pierre, South Dakota, this 3rd day of August, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in property addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 8/3/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg

JAMES A. BURG, Chairman

Pam Nelson

PAM NELSON, Commissioner

Laska Schoenfelder

LASKA SCHOENFELDER, Commissioner

NG 99-002

CONTRACT BETWEEN CHESAPEAKE REGULATORY CONSULTANTS, INC. AND THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

RECEIVED
AUG 1 1999
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

This Contract is entered into this 16th day of August, **1999**, between the **South Dakota Public Utilities Commission** (Commission) and Chesapeake Regulatory Consultants (Contractor), of 10025 Governor Warfield Parkway, Suite 301-B, Columbia, Maryland 21044-3330. The terms and conditions are as follows:

1. **Scope of Services:** Contractor agrees to provide consulting services to the Staff of the Commission in the following Commission Docket: NG99-002, In the Matter of the Application of Northwestern Public Service for Authority to Increase Rates for Natural Gas Service.

Contractor agrees to assist Staff in the preparation and presentation of testimony on behalf of Staff in the above-referenced docket including: at hearings before the Commission; in settlement proceedings; and in the preparation of motions and briefs before the Commission. Contractor through its witness or witnesses, Basil L. Copeland, Jr. and Robert G. Towers shall be responsible for: Review and analysis of Northwestern Public Service (NWPS) filings, preparation and receipt of data requests necessary to complete the analysis, preparation, filing and presentation of testimony and exhibits.

Contractor shall also be prepared to respond at hearings and during briefing to intervenors' submissions, if any, which address the issues which are the responsibility of Contractor. Specifically, Contractor Witness Basil L. Copeland, Jr. shall prepare, file, and present testimony and exhibits related to: the appropriate costs of capital and capital structure. Contractor Witness Robert G. Towers shall prepare, file, and present testimony and exhibits addressing class cost of service study issues and rate design, income tax allowance, affiliate transactions and common cost allocations, system expansion sales and cost of service top sheets. Any witness of the Contractor shall provide general assistance on the filing when requested to do so by Commission Staff.

The scope and tasks to be performed shall be consistent with Contractor's proposal dated July 13, 1999, to Commission Staff as expanded herein. Contractor agrees to coordinate their filing with Staff and as directed by Staff, shall consult Staff on requests for NWPS data and other submissions or requests to NWPS or intervenors. Contractor agrees to complete all tasks and filings within time frames as determined by Commission Staff.

It is understood and agreed that the role of Commission Staff, and in turn the role of the Contractor, shall be to advocate the public interest as Commission Staff views that public interest.

2. **Maximum Reimbursement:** The Commission agrees to reimburse the Contractor for satisfactory completion of Contractor's services in an amount not to exceed Forty-four thousand one hundred fifty-five dollars and no cents **($44,155.00)**. Services shall be paid for on the basis of time actually spent working on the case and for actual out-of-pocket costs at a rate consistent with Contractor's fee proposal to Commission Staff dated July 13,1999 which is incorporated by reference into this document and attached as Exhibit A.

If the Contractor desires to increase the maximum reimbursement under this paragraph, Contractor must notify the South Dakota Public Utilities Commission Executive Director in writing not less than thirty (30) days before monthly billings reach the maximum reimbursement. The Commission reserves the right to deny any request for an increase and may hold the Contractor to the maximum reimbursement in the original contract or amendment.

3. **Reimbursement:** The Commission agrees to reimburse the Contractor upon satisfactory progress toward completion of the tasks outlined in Paragraph 1 of this Contract. Payment up to the amount specified in the Maximum Reimbursement paragraph herein shall be made in monthly installments and shall be based on the monthly financial report as described herein. A copy of the Contractor's hourly fee schedule is appended to this Contract, which is hereby incorporated herein and will remain effective throughout the term of this Contract.

A monthly financial report shall be submitted by the Contractor which shall include the nature of the work performed, the hours worked by and charges for Contractor's out-of-pocket expenses. Receipts for such expenses shall be available to the Commission upon request. This information is for the express purpose of internal auditing by the Commission. When requesting payment, the time period or phase of service covered will be indicated on the face of the voucher.

The Contractor may receive progress payments not more frequently than monthly. Progress payments shall be based on services rendered and no payment may be made in advance of services rendered. It is agreed that the Commission shall withhold ten percent of each progress payment until the satisfactory completion of the contract. Invoices for services rendered shall be sent to the South Dakota Public Utilities Commission, Finance Officer, State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501, within ten (10) days of the calendar month billed.

4. **Consideration:** The consideration to be paid the Contractor as provided herein shall be in compensation for all Contractor's services incurred in the performance hereof.

5. **Change in Scope of Services:** If the scope of services under this Contract is modified to require additional work not herein contemplated and such modification is approved by the parties herein prior to performance and a written amendment to this

Contract is drawn identifying the approved changes, an authorization of additional funds will be made by the Commission and the maximum amount will be appropriately increased.

6. **Indemnity:** The Contractor agrees to indemnify, defend and hold harmless the State, its officers, agents and employees from any and all claims and losses accruing or resulting to any and all contractors, subcontractors, material men, laborers and any other person, firm or corporation furnishing or supplying work, services, materials or supplies in connection with the performance of this Contract and from any and all claims and losses accruing or resulting to any person, firm or corporation who may be injured or damaged by the Contractor in the performance of this Contract.

7. **Independent Contractor:** The Contractor and the agents of the Contractor in performance of this Contract shall act in an independent capacity and not as officers, employees or agents of the Commission.

8. **Contract Not Assignable:** This Contract is not assignable by the Contractor, either in whole or in part, without the written consent of the Commission.

9. **Alteration and Oral Agreements:** No alteration or variation of the terms of this Contract shall be valid unless made in writing and signed by the parties hereto. No oral understanding or agreement not incorporated herein may be binding on any of the parties hereto.

10. **Interpretation of Inconsistencies:** In the interpretation of this Contract, any inconsistencies between the terms hereof and the attachments shall be resolved in favor of the terms hereof.

11. **Subcontracts:** Contractor shall submit any subcontracts which he proposes to enter into to the Commission for its prior written approval before the Contractor enters into the same. No work may be subcontracted without the prior approval of the Commission. Upon the termination of any subcontract, the Commission shall be notified immediately.

12. **Retention of Contractor's Records:** The Contractor shall retain all records relating to direct expenses reimbursed to the Contractor hereunder and to hours of employment on this Contract by any employee of Contractor for which the Commission is billed. Such records shall be maintained for a period of three years after termination of this Contract and shall be available for inspection at any reasonable time by personnel authorized therefore by the State of South Dakota.

13. **Relationship of Commission Staff and Contractor:** Commission Staff will be permitted to work side-by-side with Contractor's Staff to the extent and under conditions that may be directed by the Executive Director of the Commission.

14. Contractor Responsible for Performance of Services: Contractor will not be permitted to utilize Commission personnel for the performance of services which are the responsibility of Contractor, unless such utilization is previously agreed to in writing by the Executive Director and any appropriate adjustment in price is made. No charge will be made to Contractor for the services of Commission employees while performing coordinating or monitoring functions.

15. Disclosure and Confidentiality: The Contractor will not disclose data or disseminate the contents of any final or preliminary report or testimony, in any form, in regard to this Contract without express written consent of the Commission. Permission to disclose information on one occasion shall not authorize Contractor to further disclose such information or disseminate the same on any other occasion.

If requested by the Commission, the Contractor shall require each of its employees or officers who will be involved in the performance of this Contract to agree to the above terms in a form to be approved by the Commission and shall supply the Commission with evidence thereof.

Each subcontract shall contain provisions similar to the foregoing, related to the confidentiality of data and non-disclosure of the same.

16. Data is Property of the Commission: Data developed for this Contract shall become the property of the Commission. It shall not be disclosed without the permission of the Executive Director. Each final report submitted shall also become the property of the Commission and shall not be disclosed except in such manner and time as the Executive Director may direct.

17. Amendment: The timing for the performance of the tasks and items contained herein, the total contract price, the date for completion of the Contract, as well as, all other terms not specifically accepted may only be altered by formal written amendment of this Contract.

18. Waiver: No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach. All remedies afforded in this Contract shall be taken and construed as cumulative; that is, in addition to every other remedy provided therein or by law. The failure of the Commission to enforce, at any time, any of the provisions of the Contract shall in no way be construed to be a waiver of such provisions, nor in any way affect the validity of this Contract or any part thereof, or the right of the Commission to hereinafter enforce each and every such provision.

19. Time is Critical: Time is of the essence in this Contract. In the event Contractor shall fail to perform the agreements on its part to be performed at the time fixed for performance of such respective agreements by the terms of this Contract or by any extension, the Commission may, at its election, terminate the Contract. Such termination

shall be in addition to and not in lieu of any other legal remedies provided by this Contract or by law.

20. Breach of Contract: In the event of any breach of this Contract, the Commission may, without any prejudice to any of its other legal remedies, terminate this Contract in accordance with the provisions of the Termination paragraph of this Contract.

21. Duration of Contract: Unless otherwise specifically provided by the terms of this Contract or by amendment thereof, the duration of this Contract shall be one year from the contract date.

22. Termination: The Commission may terminate this Contract, should Contractor fail to perform the covenants herein contained at the time and in the manner herein provided, upon five days written notice to the Contractor. In such event, the Commission shall pay the Contractor only the reasonable value of the services theretofore rendered by the Contractor as may be agreed upon by the parties or determined by a court of law. In the event of such termination, the Commission may proceed with the work in any manner deemed proper by the Commission. The Commission's cost of securing substituted performance shall be deducted from any sum due the Contractor under this Contract, with the balance, if any, to be paid the Contractor upon demand.

23. Payments Include All Taxes: Payments to be made to the Contractor, as specified herein, shall include all taxes of any description, federal, state and municipal assessed against the Contractor by reason of this Contract.

24. Workers' Compensation Insurance: The Contractor hereby warrants that it carries workers' compensation insurance for all of its employees who will be engaged in the performance of this Contract and agrees to furnish to the Commission satisfactory evidence thereof at any time the Commission may request.

25. South Dakota Law Controlling: It is expressly understood and agreed that this Contract shall be governed by the laws of the State of South Dakota, both as to interpretation and performance. Otherwise, as specified herein, no document or communications passing between the parties hereto shall be deemed a part of this Contract.

APPROVED AS TO FORM:

Karen E. Cremer 8-16-99

Karen Cremer, Special Assistant Attorney General DATE

COMMISSION:

8/16/99

William Bullard, Jr. Executive Director who, pursuant to SDCL 49-1-8.2 has been authorized to sign this contract on behalf of the South Dakota Public Utilities Commission.

CONTRACTOR:

By: _____ August 6, 1999

Chesapeake Regulatory Consultants, Inc. DATE

its President

(Title)

Chesapeake Regulatory Consultants, Inc.

10025 Governor Warfield Parkway, Suite 301-B
Columbia, MD 21044-3330

Phone: 301.596.3103 Fax: 301.596.1471

Robert G. Towers
Basil L. Copeland, Jr.
David E. Peterson

FEE SCHEDULE

		Hourly Rate
Robert G. Towers	Senior Consultant	$ 120.00
Basil L. Copeland, Jr.	Senior Economist	$ 110.00
David E. Peterson	Senior Consultant	$ 95.00

January 1, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	PETITION TO EXTEND SUSPENSION OF IMPOSITION OF TARIFF NG99-002

On June 1, 1999, Northwestern Public Service (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6.3%. The Company requested a change in rate to become effective for billings after July 1, 1999. On June 22, 1999, the Commission suspended the proposed schedule of rates for 90 days beyond July 1, 1999.

The Commission, pursuant to SDCL 49-34A-14, is authorized to further extend the suspension of the tariffs being imposed in this docket.

The Staff of the Commission hereby Petitions the Commission for an extension of the suspension of the tariffs being imposed in this docket through December 1, 1999. As grounds for this Petition, Staff represents to the Commission that it is in the process of analyzing this filing, that it has not completed that work, and that the docket is scheduled for hearing on October 20-21, 1999. Sufficient time is needed to prepare for the hearing.

Dated this 7th day of September, 1999.

Karen E. Cremer

Karen Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501
Telephone (605) 773-3201

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	ORDER EXTENDING SUSPENSION OF IMPOSITION OF TARIFF NG99-002

On June 1, 1999, NorthWestern Public Service (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6.3%. The Company requested a change in rate to become effective for billings after July 1, 1999. On June 22, 1999, the Commission suspended the proposed schedule of rates for 90 days beyond July 1, 1999. On September 7, 1999, Commission Staff filed a Petition with the Commission requesting that the suspension of the tariff be further extended through December 1, 1999.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.1, 49-34A-10, 49-34A-11, 49-34A12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

At its September 8, 1999, meeting, the Commission considered this matter. NWPS stated that it did not object to the extension. The Commission voted unanimously to grant the extension sought by Commission Staff. It is therefore

ORDERED that the proposed schedule of rates shall be suspended through December 1, 1999, pursuant to SDCL 49-34A-14.

Dated at Pierre, South Dakota, this 14th day of September, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kacko

Date: 9/14/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg

JAMES A. BURG, Chairman

Pam Nelson

PAM NELSON, Commissioner

Laska Schoenfelder

LASKA SCHOENFELDER, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	CERTIFICATE OF SERVICE NG99-002

I hereby certify that copies of Testimony and Exhibits of David A. Jacobson, Testimony of Martin C. Bettman, Testimony and Exhibits of Michele M. Farris, Testimony and Exhibits of Keith A. Senger, Testimony and Exhibit of Basil L. Copeland Jr., and Testimony of Robert G. Towers were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this the 24th day of September, 1999.

Mr. Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service
600 Market Street West
Huron, SD 57350

Mr. Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street S.E.
Huron, SD 57350

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

RECEIVED
SEP 24 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

NorthWestern Public Service
Application to Increase Gas Rates in South Dakota
Docket No. NG99-002

Testimony of Robert G. Towers
on Behalf of the Commission Staff

September, 1999

I. Qualifications

Q. Please state your name, business address and occupation.

A. Robert G. Towers. I am a public utility rate consultant and a principal in the firm Chesapeake Regulatory Consultants, Inc. My office is at 10025 Governor Warfield Parkway, Suite 301-B, in Columbia, Maryland, 21044-3330.

Q. Does the Appendix to this testimony describe your education and summarize your experience in public utility regulation?

A. Yes, it does.

Q. Have you testified previously before the South Dakota Public Utilities Commission?

A. Yes. Since 1976 I have testified on behalf of the Commission Staff in more than thirty rate cases involving each of the investor-owned gas distribution and electric utilities in the state and U.S. West and I have consulted with the Staff in connection with other proceedings.

Q. Have you testified in or otherwise been involved in proceedings concerning the rates of NorthWestern Public Service ("NPS" or "the company")?

A. Yes, although the utility was then known as Northwestern Public Service Company ("NWPS"). I testified for the South Dakota Commission Staff in four

NWPS electric or gas rate cases – Docket Nos. F-3301 (1979), F-3367 (1981), F-3420 (1984), and F-3498 (1984) and I assisted the Staff in its NWPS investigations related to the Tax Reform Act of 1986 and the ratemaking disposition of employer costs of retiree health care benefits.

II. Scope of Assignment and Overview of NPS' Rate Filing

Q. For what purpose was your firm retained in this case?

A. We were retained to address specific issues raised by the company's filing, to work with members of the Commission's South Dakota staff in pursuit of other issues and to prepare and present to the Commission summary accounting exhibits combining the results of all of these efforts. Mr. Basil L. Copeland of our firm was designated to perform a cost of capital analysis and to present his recommendations on the issues of the appropriate capital structure and rate of return for NPS' gas utility.

I was designated to analyze and prepare testimony regarding the propriety of NPS' transactions with its affiliates, cost allocations reflected in the filing, the appropriate ratemaking allowance for income taxes and the allocation of gas utility system costs to various classes of customers. I was also asked to present the summary exhibits reflecting the Staff's determination of NPS' South Dakota gas utility revenue requirement.

Q. What is the nature of NPS' rate filing in this docket?

A. The company is proposing to increase its South Dakota gas service base rates in the aggregate amount of $2.1 million based on weather normalized and adjusted 1998 sales. The increase is described by NPS' President and CEO as a 6.26% adjustment to existing rates established in a rate filing made in 1994. The need for an increase at this time is attributed to higher operating costs and the need to reflect the effects of the distribution system expansion that has taken place since 1994.

The proposed allocation of the rate increase among residential, small commercial and larger commercial and industrial customers is based on an allocation of costs to each

class including a uniform rate of return on rate base.

Q. Is the company correct to characterize its rate proposal as a 6.26% increase?

A. It is correct but misleading. While it is true that, if adopted, the proposed rates would increase customers' bills by an overall 6.26%, these bills include a large component -- the cost of purchased gas -- that is adjusted independently and, thus, is unrelated to the *base rate* increases that are being considered in this case. A comparison of the present and proposed *base rate* revenues shows that the company is seeking a hefty 17.8% increase[1] in this component of customer bills to cover the non-gas cost changes that have occurred during the five year period since the last base rate filing. By comparison, the Consumer Price Index has risen by only about 12% over the same period[2]

III. Summary of Conclusions and Recommendations

Q. Please briefly summarize your conclusions and recommendations.

A. My disagreements with NPS concern three issues -- its transactions with affiliates, the allowance which it has claimed for Federal income taxes and the evidence it relies upon to support its proposed monthly customer service charges.

The issue of NPS' **transactions with affiliates** has a special importance in this case because of the corporate restructuring and aggressive growth into unregulated activities that has occurred since 1994. I am making two recommendations in this area:

* First, I recommend that the company be required to institute formal procedures to track and account for time spent by employees of NPS' parent company, the corporate service company and other affiliates on matters affecting and chargeable to the utility, NPS. The recent restructuring of the corporation has made it

[1] Compare column (c), line 2 on pages 1 and 2 of Exhibit___(TPH-2).

[2] The CPI - All Urban Consumers increased from 149.0 in August, 1994 to 167.1 in August, 1999, the latest month for which data are available. 167.1/149.0 = 12.1% increase.

difficult and impossible in the time available in a rate case, to identify and to test the validity many of the charges incurred by NPS. I recommend a system of accountability based on rules promulgated by the Securities and Exchange Commission and used by many utilities having substantial transactions with corporate affiliates.

* Second, I recommend an adjustment to remove from the claimed revenue requirement a portion of the payments made by NPS to its affiliate Northwestern Energy Company ("NEC") for the purchase of pipeline capacity from NEC's subsidiary, Nekota Resources ("Nekota"). My proposed adjustment recognizes that only a portion of the pipeline's capacity is dedicated to NPS and that the claimed charges to NPS greatly exceed Nekota's costs. The adjustment, which is based on Nekota's actual investment in the transmission line, reduces NPS' claimed annual revenue requirement by $470,210.

As to the appropriate **income tax allowance** for NPS in this case, I recommend that the Federal income tax allowance calculated at the statutory rate of 35 percent as if NPS were a stand-alone taxpayer be reduced by a share of the income tax savings which have been accruing to the actual corporate taxpayer through the filing of a consolidated income tax return. The consolidated tax return is the vehicle by which the taxable losses of NPS' affiliates have reduced the taxable income of other affiliates, including NPS, in each of the last three years. This adjustment reduces the claimed revenue requirement by $281,034.

With respect to the **class cost allocation** used for the purpose of distributing the company's total revenue requirement among residential, small commercial and large commercial/industrial gas customers, I agree with the methodologies used by NPS. The methodologies are consistent generally with those reflected in the Staff's recommendations and recent settlement of MidAmerican's gas rate case in Docket No. NG98-011. Moreover, as in *MidAmerican,* while I disagree with the company's determination of costs to be collected through the fixed monthly **customer charge,** I find that the proposed charges do not exceed my determination of the relevant costs. I therefore recommended to Mr. Bettman that, subject to his tempering with other other rate design considerations, the proposed customer charges could be adopted.

Q. **Have you prepared an exhibit combining the revenue requirement recommendations of all Staff witnesses?**

A. Yes. Exhibit____(RGT-1) incorporates the sales adjustments recommended by Mr. Bettman, the incentive compensation, association dues and economic development adjustments proposed by Ms. Farris, the rental income and rate case expense adjustments sponsored by Mr. Senger, the cash working capital requirement and gas in storage rate base determinations made by Mr. Jacobson, and my pipeline capacity charge and income tax adjustments. It also reflects Mr Copeland's cost of capital recommendations. Schedule 1 of the exhibit shows that, based on the 1998 test year, as proposed by the company, Staff's recommendations indicate an annual revenue deficiency of $402,290.

A rate increase of $402,290 represents an increase of 1.20% in customer bills (corresponding to the company's proposed 6.26%) or, as I prefer to view it, an increase of 3.4% in the base rate revenue generated with NPS' existing rates. Mr. Bettman has developed tariff rates based on this determination.

IV. Transactions with Affiliates

Q. What are the affiliate relationships of NPS and its parent company, NorthWestern Corporation?

A. The affiliate relationships can most easily be described by the corporate organization chart provided by the company and reproduced in Exhibit___(RGT-2). NorthWestern Public Service is a division of NorthWestern Corporation. Other companies of particular interest are NorthWestern Services Corporation and NorthWestern Energy Corporation ("NEC"), both direct subsidiaries of NorthWestern Corporation, and Nekota Resources, Inc., a subsidiary of NEC.

As explained by Mr. Monaghan at page 4 of his testimony, NEC engages in non-regulated energy sales and marketing businesses; while NorthWestern Services provides energy system services to residential and business customers over a seven-state region. And, as I mentioned earlier, Nekota sells pipeline capacity to NEC for resale to NPS.

Q. What were the test year transactions between NPS and its affiliates?

A. The following table summarizes the Company's 1998 affiliate expenses charged to South Dakota gas operations.

Affiliate	1998 Charges (So. Dakota - Gas)	Service Provided
NorthWestern Services	$1,037,568	Management
NorCom Advanced Technologies	130,224	Management
NorthWestern Energy	192,684	Management
Subtotal - Management	$1,360,476	
NorthWestern Energy	$ 576,000	Pipeline Capacity
Total	$1,936,476	

A proforma adjustment to South Dakota gas allocation factors reduced these amounts slightly for the test year. More importantly, the rate filing reflects a decrease of $1.1 million (from $3.6 million to $2.5 million) in the management fee charged by NorthWestern Services to NPS. South Dakota gas operations share of this decrease is $315,947. On a proforma basis, the rate filing includes $1,585,021 of affiliate charges to NPS, of which $1,009,021 represents fees for management services.

Affiliate charges to the company's South Dakota gas operations are provided in Statement R of the rate filing package, supplemented by its responses to Staff's data requests.

Q. Why is it important for the Commission to scrutinize NPS' transactions with affiliates in this case?

A. Obviously, it is important to examine such transactions in any case, but it is especially important here because of the changes in the organization's corporate structure that has occurred since the Commission last examined NPS' gas or electric rates. NPS' corporate parent has acquired and greatly expanded new business lines in addition to its regulated gas and electric businesses and NPS' regulated business operations are substantially different from those of the former NWPS. NPS now "outsources" many of the management and personnel functions that were formerly provided internally although many of these services are provided by former employees of NWPS who are now employed by NPS' affiliates.

Outsourcing might result in lower costs and, thereby, be beneficial to NPS' utility customers. However, in several instances, NPS' functions are being outsourced to its

unregulated affiliates and there has been no demonstration that many of these less-than-arm's length transactions are competitively priced. The same unregulated affiliates providing services to NPS also provide services to other unregulated affiliates and unaffiliated entities.

In sum, because there can be no independent arm's length relationship among affiliates, the Commission should remain concerned that there be an appropriate allocation of just and reasonable costs for services that are necessary and prudent for NPS. This concern applies equally to costs incurred on behalf of NPS' gas and electric customers.

Q. Have you reviewed in detail all of the transactions between NPS and its affiliates to determine if the costs claimed by NPS are reasonable and necessary?

A. I was able to make such a determination with respect to the purchase of pipeline capacity from NPS' affiliate Nekota through NEC because that transaction is straightforward and contractual. Analyzing the claimed charges for management services provided by unregulated affiliates, however, proved to be more difficult.

The Staff asked numerous questions attempting to ascertain the bases for and validity of fees for management services. We learned that the arrangements between the utility and the affiliates who provide "management services" are not governed by any formal agreement or contract; that the services themselves are not specifically identified; that there is no documentation for the allocation of common and joint costs among the participants; and that, in most instances, the charges are not based on actual costs that are currently being incurred to render the service. Thus, we have no hard evidence upon which to conclude that the claimed level of management service fees is appropriate.

Q. What is the basis for your statement that management fees are not based on actual costs currently incurred to render these services?

A. We were informed that, at the beginning of each year, the affiliated management service companies establish an annual fee and allocation formulae that remain in effect during the entire year. With this procedure, NPS is billed a fixed monthly charge for management services regardless of the actual level of its requirements for any such services.

Q. Why is this a problem?

A. Obviously a fixed fee for services does not track the actual level of NPS' requirements for any such services during the period. Moreover, one can have no confidence that it will recognize the service company's ability to provide the service. This is a concern where, as with NorthWestern Corporation at present, the demands of other affiliates may usurp the resources for which NPS is being charged. Also, because the management fee now purports to be based on the prior year's experience, it seems likely that the more rapid growth of NPS' unregulated affiliates would lead to a continual underpricing of services to these affiliates while services actually rendered to NPS would be overpriced.

Q. Is there evidence that the charges to NPS for these services have been overpriced in this case?

A. Fortuitously, in this case, there is evidence *suggesting* that the charges for management services have *not* been overpriced. I mentioned earlier that one of the proforma adjustments to the 1998 test year was made to reflect a reduction in the management fee charged to NPS by NorthWestern Services. The reduced fee of $2.5 million to NPS as a whole is about $1.1 million lower than the actual 1998 fees and the corresponding costs incurred directly or indirectly by NWPS in the preceding two years. While this does not prove that the $2.5 million fee is necessary or reasonable, it represents a significant cost reduction that will be passed on to ratepayers and serves to mitigate concerns that the new scheme for providing management services is harmful at this time.

Q. What, in your opinion, should be done to address the problems with the pricing of management services provided by affiliates to NPS?

A. In light of the $1.1 million cost reduction that already is reflected in the rate filing, I would make no further adjustment or disallowance in this case. However, I believe that it is essential to the future effective rate regulation of NPS' gas and electric operations that affiliates' charges to NPS be formalized in service agreements or contracts. These agreements should specifically identify the services that are to be provided under the agreement and the bases for the associated charges. In short, NPS should be subject to the same general type of controls that the SEC requires of participants to service company agreements under the Public Utility Holding Company Act of 1935.

Q. **Specifically, what should be required?**

A. Management services provided to NPS by affiliates should be furnished at the actual cost of providing these services. Detailed records should be required to establish costs and to determine the cost of providing specific services. These costs would include wages and salaries of employees, fees, charges by suppliers and contractors for supplying goods and services, and closely related expenses such as insurance, taxes, pensions, other employee welfare expenses, and general administrative expenses.

Whenever possible personnel costs and expenses should be directly assigned to a service company project or affiliated client (e.g. NPS) and directly billed to the project or affiliated client receiving the service. In the case of NorthWestern Corporation, I would expect that most of the charges incurred by the management companies would consist of identifiable costs that would be directly billed to those requesting the service. When a service is rendered for the benefit of two or more companies and the benefits cannot be charged directly, those costs should be equitably shared by the receiving companies using an agreed-upon formula that fairly reflects the relative benefits received. The service agreements should be reviewed periodically to reflect changing circumstances.

Q. **You earlier indicated that you are recommending an adjustment to the charge imposed on NPS by its affiliate NorthWestern Energy Corporation (NEC) for the use of pipeline capacity. Please explain this transaction.**

A. NPS' gas supply to Aberdeen enters the distribution system through two pipelines. One is a pre-existing connection to Northern Natural; the other is a pipeline owned by Nekota Resources, Inc. ("Nekota"), a subsidiary of NEC and, thereby, an affiliate of NPS. Nekota is connected to Northern Border Pipeline.

NEC entered into a contract with Nekota, dated November 1, 1996, whereby Nekota provides transportation service to NEC. By separate contract effective on the same date, NPS entered into a transportation services agreement with NEC. The rates in the two agreements are the same. The contracts are for an initial term of ten years but only the contract between Nekota and NEC is renewable by mutual agreement for an additional ten years.

NPS' entitlement represents 62.5% of the capacity of Nekota's pipeline. For this it pays $48,000 per month, or $574,000 per year all of which is assigned to South Dakota gas operations.

Q. Is this a reasonable charge?

A. No. It greatly exceeds the affiliate's (Nekota) cost of providing the service. It is also an example of how "outsourcing" allows an enterprise to use a regulated utility affiliate to enhance its opportunities in unregulated markets.

Q. How do you know that the $574,000 annual charge greatly exceeds Nekota's cost of providing the service?

A. Information provided by the company indicates that Nekota's investment in the pipeline is $1,185,000. An annual rental of $574,000 for a facility with an expected life of at least 20 years costing $1.2 million is excessive on its face. But combining this with the facts that (i) only 62.5 percent of the capacity of the line is committed to NPS and (ii) that, by separate agreement, NPS is obligated during the first five years of its contract to pay all inspection costs and operation and maintenance expenses, makes it abundantly clear that the charge is excessive, unreasonable and unjustified.

Q. How do these contractual arrangement position NorthWestern Corporation to use NPS to the competitive advantage of its unregulated affiliates?

A. The contract requires payments from NPS that are more than sufficient to pay for the entire line but leaves 37.5% of the capacity uncommitted and available to NEC, the energy marketing affiliate. Moreover, the fact that NEC's contract with Nekota is renewable for an additional ten years, while NPS contract with NEC is not, leaves open the possibility that, after the 10-year term of its contract, NPS will not be able to use the Nekota pipeline at all -- or at a reasonable cost -- if the market for gas transportation provides more lucrative opportunities for NEC.

Q. How are you proposing to deal with this issue?

A. I have developed on page 3 of Schedule 3 of Exhibit___(RGT-1) a $470,210 adjustment, reduces the $576,000 annual charge to $105,790. The $105,790 annual allowance represents 62.5% of the levelized cost of service of the Nekota pipeline based on its actual original cost ($1,185,000), excluding any allowance for O&M costs inasmuch as these expenses are to be paid directly by NPS until December 31, 2001. Thus the cost of

service consists of Staff's recommended rate of return and associated income taxes and an allowance for property taxes. Conservatively, it is assumed that that the life of the plant is limited to 20 years based on NEC's contract with Nekota. The allowance is 62.5% of the cost of service because this fraction reflects the extent to which the pipeline capacity is dedicated to NPS.

The adjustment developed on page 3 of Schedule 3 is properly used in my exhibit to determine the company's deficiency in total revenues, as on my Schedule 1 and on page 1 of Mr. Hitchcock's Exhibit___(TPH-1). However, my recommendations use the NEC/Nekota payment disallowance to reduce the proposed base rates which are at issue in this case. After reviewing the company's recent (September 1, 1999) PGA filing and finding in it an item labeled "NBPL - Aberdeen Capacity" in the annual amount of $576,000, I believe that NPS is now (and probably has been) collecting these affiliate costs through the PGA where they are referenced to "NBPL" or Northern Border Pipeline. If this is what is happening, the adjustment that I am proposing here should be implemented as a reduction in the PGA rather than base rates. The Staff recommended base rates would be increased by $470,210 and the PGA reduced by the same amount.

V. Income Tax Allowance

Q. What does NPS claim as an allowance for Federal income taxes in its rate case revenue requirement?

A. The claimed income tax allowance, reflecting the requested return on rate base, is shown in column (g) on page 1 of Mr. Hitchock's Exhibit___(TPH-1) to be $1,212,276. It is developed on page 45 of his exhibit, effectively, by applying the 35% statutory tax rate to a calculated amount representing the South Dakota gas utility portion of NPS' separate return taxable income and increasing this amount for deferred income taxes. By "separate return taxable income" I mean the taxable income that would appear on its tax return if NPS actually filed such returns with the Internal Revenue Service.

Q. Does NPS file such returns with the IRS?

A. No. As I explained earlier, NPS is not a separate corporate entity; it is a division of NorthWestern Corporation. Moreover, NorthWestern Corporation has numerous direct

and indirect subsidiaries engaged in unregulated activities. The actual income tax payable to the U.S. Treasury is determined by combining the income and income deductions of the affiliated group into a consolidated income tax return. The consolidated return is filed by NorthWestern Corporation.

Q. Why does NorthWestern Corporation file a consolidated income tax return?

A. The consolidated return is a vehicle for minimizing the corporate income tax liability. It has reduced the corporate income tax liability for NorthWestern Corporation in each of the last three years, 1996 through 1998.

Q. How does the consolidated return achieve these tax savings?

A. The consolidated return enables NorthWestern Corporation to use taxable losses generated by some of its subsidiaries to reduce the taxable income generated by other subsidiaries. This has been true in each of the last three years – that is, ever since NorthWestern Corporation embarked on its aggressive program's of restructuring, acquisitions and expansion of its unregulated activities.

Q. What are the ratemaking implications of these tax reductions?

A. Rates should be based on actual costs and costs should be minimized within the bounds of maintaining the utility's ability to render safe, adequate and reliable service. Thus, whenever a consolidated return is – or should be – filed to minimize corporate income taxes, the ratemaking allowance for income taxes should reflect an appropriate share of the tax benefits.

Q. Are there risks to regulated entities of participating in a consolidated return?

A. Yes. Treasury Regulation 1.1502-6 provides that each member of a group filing a consolidated return is severally liable for the entire tax of the group. Thus, ratepayers are exposed to a tax liability that may be far greater than the tax that would be levied on the utility if it filed a separate tax return. For example, based on preliminary data for 1998, NPS' regulated electric and gas operations generated taxable income of about $10 million which, at the statutory 35% tax rate, suggests a separate return tax of about $3.5 million. Taxable income for the consolidated entity amounted to over $25 million indicating an actual tax liability -- and exposure for each participant -- of $8.75 million. Allowing

ratepayers to share in the demonstrated benefits of the consolidated tax return is a means of balancing this exposure.

Q. What are the demonstrated benefits of the consolidated returns filed by NorthWestern Corporation?

A. The ability of NorthWestern Corporation to use the tax losses of certain subsidiaries as offsets to the taxable income of other subsidiearies is illustrated on Schedule 3 of my Exhibit___(RGT-1) at page 4. In each of the last three years there were participants with taxable income averaging, for the group, some $38.4 million. However, the actual (consolidated) taxable income was only $19.0 million because the $38.4 million was reduced by the average $19.4 million taxable losses of the other participants. NPS has been part of the group with taxable income.

Obviously, the benefits of the consolidated return have been substantial and recurring for NorthWestern Corporation.

Q. Is there a nexus between NPS and affiliates that generate taxable losses?

A. Yes. It is no coincidence that many utilities are able to engage in aggressive expansion into unregulated businesses. Utilities have often been referred to as "cash generators" and it is the availability of this cash and good credit standing that is a springboard for diversification and expansion. This linkage was acknowledged only recently in NorthWestern's August 4, 1999 *News from NorthWestern* newsletter in which its President and COO, Richard R. Hylland, observed that the Company's "dynamic growth" is "driven by a combination of CornerStone's agressive expansion programs, NorthWestern Public Service's cash flow generation, and internal and external growth at Blue Dot. And Expanets..." (emphasis supplied).

This is one more reason that NPS' ratepayers should be allowed to share in the benefits of the consolidated tax return.

Q. How did you reflect these benefits in the income tax allowance that you are recommending in this case?

A. Page 4 of Schedule 3 shows that I have allocated to NPS' South Dakota gas operations a share of the actual taxable losses contributed to the consolidated return by the entities

having taxable losses. To minimize the effects of year-by-year differences, I used as an allocation factor the ratio of the three-year averages of (i) NPS' gas operations separate return taxable income to (ii) the taxable income of all entities having taxable income. I considered applying this factor to the three-year average of the taxable losses but because this experience shows a decline in the aggregate losses during the period, I used the most recent, lowest level of taxable losses.

On this basis I allocated to NPS gas operations 7.99% of the $11,876,670 of taxable losses contributed by the tax loss participants in 1998. Fifty-five percent of the NPS gas amount, or $521,920, is attributed to South Dakota gas operations. Applying the 35% statutory rate to this amount produces a consolidated tax savings of $182,672 which is used to reduce the hypothetical tax allowance computed on a separate return basis. The revenue requirement effect of this adjustment is a reduction of $281,034.

VI. Class Cost of Service Study and Monthly Customer Charges

Q. Have you prepared an analysis of the company's revenue requirements by customer class?

A. Yes. Exhibit___(RGT-3) summarizes this study. It reflects the Staff's determination of NPS' overall South Dakota gas revenue requirement developed in Exhibit___(RGT-1) but it employs the cost of service methodology used by NPS. As I mentioned earlier, I have no quarrel with the company's methodology; it is fundamentally the same methodology proposed by Staff in the recently-settled MidAmerican gas rate case, Docket No. NG98-011.

The cost determinations by rate class establish the Staff's recommended overall rate of return of 8.42% as the target return for each class. This too is the procedure used by NPS and is one with which I agree.

As indicated on page 1 of the exhibit, line 26, the earned rates of return with present rates are below the 8.42% target rate of return for all classes. Comparing the revenues at present rates on line 2 of page 1 with the revenues at the required rate level on line 2 of page 2 indicates the revenue deficiencies by class:

	Revenue Deficiency	Required Increase
Rate 81 - Residential	$ 246,189	3.25%
Rate 82 - Small Commercial	134,587	5.78%
Other - Lge. C & I	21,514	1.05%
Total	$ 402,290	3.41%

These are the revenue deficiencies used by Mr. Bettman to develop the tariff rates recommended by Staff.

Q. **What changes in monthly customer service charges are being proposed by NPS?**

A. Mr. Hitchcock proposes to increase the fixed monthly customer charges as follows:

	Present	Proposed	Increase	
Rate 81 - Residential	$4.50	$6.00	$1.50	33%
Rate 82 - Small commercial	$4.50	$7.00	$2.50	56%

Customer charges for Large commercial and industrial accounts are proposed to be increased in varying amounts by rate schedule and to establish a charge for transportation customers that is $50 higher than for comparable sales customers. Option A sales customers on Rates 84 and 85 would have their customer charge increased by $10 per month or 14%; Option B sales customers would be increased by $20 but the larger increase is only 8% above their existing rate. Transportation customers on Rate 87, for whom the present customer charge is the same as for Rates 84 and 85 counterparts, would have their customer charge increased by the amounts applicable to Rate 84 and 85 customers plus an additional $50 per month.

Q. **Are you convinced that the proposed monthly service charges are appropriate?**

A Yes, I believe that they are cost-justified. However, I do not agree with the cost determinations made by the company which imply that even the proposed charges are inadequate.

Q. Please explain.

A. Mr. Hitchcock's determination of the "customer charge requirement" on page 4 of Exhibit___(TPH-2), purports to show that, while charges of $6.00 and $7.00 are being proposed for Residential and Small Commercial customers, the associated costs are more than double these amounts. I disagree with this conclusion because many of the costs that he has included are not among the generally unavoidable costs directly associated with providing service incrementally to individual customers. His cost determinations reflect large amounts of corporate overhead costs which are not directly related to the provision of service to individual customers. These overhead costs support all system functions and they are controllable to a greater extent than the direct costs related to Service lines, Meters and customer billing and accounting functions. And they do not increase or decrease when a customer is added or lost.

Q. How, in your opinion, should one determine the costs that might properly be included in a customer service charge?

A. I would limit this determination to the costs that are *directly* related to providing service access to a customer. These are the categories of costs that would be affected, incrementally, when a customer is added to the system. The costs would include the carrying charges on investment and the operating expenses related to customer Services, Meters and Regulators and the costs of meter reading and billing.

Q. Have you determined the costs that you believe are directly related to providing NPS' customers with access to service?

A. Yes. This determination is summarized in Exhibit___(RGT-4). And, while it shows costs that are substantially below those tabulated by Mr. Hitchcock, they still exceed the proposed customer charges. For example, while Mr. Hitchcock's determination of Residential customer costs is $13.88, my determination shows $8.22 which remains above the proposed $6.00 charge. Accordingly, I recommended to Mr. Bettman that, within the constraints of his other rate design considerations, the proposed charges be

considered for adoption.

Q. **Do I understand correctly that, in your opinion, it is not necessary to recover all of these costs through a service charge?**

A. Yes. While all of these costs may properly be recovered in a monthly service charge, they need not be recovered in this manner. Obviously, assigning a portion of these costs to the commodity rate would still allow them to be recovered by the company. But collecting a portion of these costs through the commodity rate also injects sensitivity to customer size into the recovery of these costs. .

Q. **I have no further questions at this time.**

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VI. Class Cost of Service Study and Monthly Customer Charges ....Page 14

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Mr. Towers is President of Chesapeake Regulatory Consultants, Inc. Over the past thirty-nine years he has assisted clients in dealing with a wide range of ratemaking policy, accounting, financial, economic and operational issues affecting rates and services offered by all types of utilities. He has testified in more than 180 public utility rate proceedings before regulatory commissions in 26 states and the District of Columbia, the Federal Energy Regulatory Commission and its predecessor the Federal Power Commission.

EMPLOYMENT

1986 - Present	President and Senior Consultant Chesapeake Regulatory Consultants, Inc. Columbia, Maryland
1970 - 1986	Vice President and Senior Consultant Hess & Lim, Inc. Greenbelt, Maryland
1960 - 1970	Consultant Martin Toscan Bennett Associates Washington, D.C.

As a consultant with each of the firms listed above, Mr. Towers participated extensively in wholesale and retail rate proceedings before federal and state regulatory agencies on behalf of the firms' clients. His participation involved analyses of a broad range of ratemaking concept, accounting, financial, operational, allocation and rate design issues raised by the utility's rate filings or otherwise uncovered. Tasks performed included analysis of the utility's supporting documentation, assistance with discovery and cross-examination, presentation of affirmative testimony, assistance with the preparation of legal briefs and other pleadings, and assistance in settlement negotiations. The subject utilities included electric, gas, steam and water distribution companies; electric generating utilities; gas and products pipeline companies; waste water systems; transit companies; and telecommunication companies.

Clients served by Mr. Towers have included numerous state regulatory commissions and their staffs; consumer advocate agencies of state governments; federal government agencies (as consumers of utility services); cities (as consumers of utility services and as representatives of their citizens); civic organizations; municipally-owned and cooperative utility systems; industrial consumers; and investor-owned utilities (principally as purchasers of utility services from others).

EDUCATION

June 1960 Bachelor of Science Degree in Economics
University of Maryland
College Park, Maryland
Phi Eta Sigma and
Phi Kappa Phi Honor Societies

PROFESSIONAL ORGANIZATIONS

American Economic Association
American Water Works Association

PUBLICATIONS & SPECIAL APPEARANCES

Article "Cost of Debt Capital in Allowed Rates of Return" published in Public Utilities Fortnightly, Vol. 68, No. 1.

Paper "Ratemaking Consideration of Construction Work in Progress" presented to the Conference of State Utility Consumer Advocates, University of Chicago, June 1979.

Paper on CWIP treatment presented to the Iowa State Regulatory Conference, Iowa State University, May 1980.

EXPERT TESTIMONY

Mr. Towers has presented testimony to the following regulatory authorities in more than 180 proceedings.

Arkansas Public Service Commission
Connecticut Public Utilities Control Authority
Delaware Public Service Commission
District of Columbia Public Service Commission
Florida Public Service Commission

Hawaii Public Utilities Commission
Idaho Public Utilities Commission
Iowa Public Utilities Board
Maryland Public Service Commission
Massachusetts Department of Public Utilities

Minnesota Public Utilities Commission
Mississippi Public Service Commission
Montana Public Service Commission
Nevada Public Service Commission
New Mexico Public Service Commission

New York Public Service Commission
Ohio Public Utilities Commission
Pennsylvania Public Utility Commission
Rhode Island Public Utilities Commission
South Dakota Public Utilities Commission

Texas Public Utility Commission
Texas Railroad Commission
Vermont Public Service Board
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission
Wisconsin Public Service Commission
Wyoming Public Service Commission

Federal Energy Regulatory Commission
Federal Power Commission

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NORTHWESTERN PUBLIC SERVICE
South Dakota Gas Operations
Revenue Deficiency
Test Year Ended December 31, 1998

	(A)	(B)
1.	Average rate base	$36,190,783
2.	Operating income under current rates	2,780,930
3.	Pro forma rate of return	7.68%
4.	Staff recommended rate of return	8.42%
5.	Income requirement	$3,047,264
6.	Operating income under current rates	2,780,930
7.	Income deficiency	$266,334
8.	Income taxes @ 35%	143,411
9.	Revenue deficiency	$409,745
10.	Gross receipts taxes @ .15%	603
11.	MGP removal cost adjustment	(8,058)
12.	Total revenue deficiency	$402,290

Sources:
Line 1: Schedule 2, page 1
Line 2: Schedule 3, page 1
Line 4: Page 2, herein

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Capital Structure and Rate of Return
Test Year December 31, 1998

	Capitalization Ratios	Cost Rate	Weighted Cost
(A)	(B)	(C)	(D)
1. Long-term debt	62.4896%	7.1121%	4.4443%
2. Preferred stock	0.7097%	5.1133%	0.0363%
3. Common equity	36.8007%	10.6957%	3.9361%
4. Total	100.0000%		8.4167%

Source: Staff Witness Copeland

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Average Rate Base
Test Year Ended December 31, 1998

		Commission Staff	
	As Filed	Adjustments	As Adjusted
(A)	(B)	(C)	(D)
Plant in service			
1. Direct South Dakota gas plant	$41,073,199	$0	$41,073,199
2. Common plant	7,949,560	0	7,949,560
3. Subtotal	$49,022,759	$0	$49,022,759
Distribution replacements			
4. Distribution mains	0	0	0
5. Distribution services	0	0	0
Construction in service, not transferred			
6. Direct South Dakota gas plant	1,854,584	0	1,854,584
7. Common plant	161,858	0	161,858
8. Total plant and property	$51,039,201	$0	$51,039,201
Accumulated depreciation and amortization			
9. Direct South Dakota gas plant	14,215,894	0	14,215,894
10. Common plant	1,071,470	0	1,071,470
11. Total reserve	$15,287,364	$0	$15,287,364
12. Net utility plant	$35,751,837	$0	$35,751,837
13. Working capital	1,720,172	(703,577)	1,016,596
14. Unamortized rate case expense	125,000	(80,000)	45,000
15. Deferred tax reserve	(622,650)	0	(622,650)
16. Rate base	$36,974,359	($783,577)	$36,190,783

Sources
Column B: NWPS Exhibit TPH-1, page 47
Column C: Page 2, herein

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Commission Staff Rate Base Adjustments
Test Year Ended December 31, 1998

	Cash Working Capital	Gas Storage	Rate Case Expense					Summary of Adjustments
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Plant in service								
1. Direct South Dakota gas plant								$0
2. Common plant								0
3. Subtotal	$0	$0	$0	$0	$0	$0	$0	$0
Distribution replacements								
4. Distribution mains								0
5. Distribution services								0
Construction in service, not transferred								
6. Direct South Dakota gas plant								0
7. Common plant								0
8. Total plant and property	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated depreciation and amortization								
9. Direct South Dakota gas plant								0
10. Common plant								0
11. Total reserve	$0	$0	$0	$0	$0	$0	$0	$0
12. Net utility plant	$0	$0	$0	$0	$0	$0	$0	$0
13. Working capital	(665,787)	(37,790)						(703,577)
14. Unamortized rate case expense			(80,000)					(80,000)
15. Deferred tax reserve								0
16. Rate base	($665,787)	($37,790)	($80,000)	$0	$0	$0	$0	($783,577)

Sources:
Columns B,C: Staff Witness Jacobson
Column D: Staff Witness Senger

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Pro Forma Income Under Present Rates
Test Year Ended December 31, 1998

		Commission Staff	
	As Filed	Adjustments	As Adjusted
(A)	(B)	(C)	(D)
Operating revenue			
1. Gas sales revenue	$32,065,804	$16,541	$32,082,345
2. Transportation revenue	1,427,347	(19,410)	1,407,937
3. Other revenue	163,923	3,445	167,368
4. Total revenue	$33,657,074	$576	$33,657,650
Operating expenses			
5. Cost of gas supply	21,484,514	12,882	21,497,396
6. MGP removal cost adjustment	1,318,450	474	1,318,924
7. Operating and maintenance	5,686,154	(585,888)	5,100,266
8. Depreciation and amortization	1,616,790	0	1,616,790
9. Taxes other than income	973,857	335	974,192
10. Federal income taxes	472,723	(121,571)	351,152
11. Rate case expense	50,000	(32,000)	18,000
12. Total operating expenses	$31,602,488	($725,768)	$30,876,720
13. Net operating income - pro forma	$2,054,586	$726,344	$2,780,930

Sources:
Column B: NWPS Exhibit TPH-1, page 1
Column C: Page 2, herein

NORTHWESTERN PUBLIC SERVICE
South Dakota Gas Operations
Commission Staff Income Adjustments
Test Year Ended December 31, 1998

	Correct Sales Error	Wolsey Sales	Office Rent	Incentive Compensation	Assoc. Dues and Econ. Development	Rate Case Expense	Nekota Pipeline Charges
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Operating revenue							
1. Gas sales revenue	$16,541						
2. Transportation revenue		($19,410)					
3. Other revenue			$3,445				
4. Total revenue	$16,541	($19,410)	$3,445	$0	$0	$0	$0
Operating expenses							
5. Cost of gas supply	12,882						
6. MGP removal cost adjustment	474						
7. Operating and maintenance				(88,342)	(27,336)		(470,210)
8. Depreciation and amortization							
9. Taxes other than income	359	(29)	5				
10. Federal income taxes	989	(6,783)	1,204	30,920	9,568	11,200	164,574
11. Rate case expense						(32,000)	
12. Total operating expenses	$14,704	($6,812)	$1,209	($57,422)	($17,768)	($20,800)	($305,637)
13. Net operating income - pro forma	$1,837	($12,598)	$2,236	$57,422	$17,768	$20,800	$305,637

Sources:
Column B: NWPS response to Staff Request 3-01
Column C: Staff Witness Bettman
Column D: Staff Witness Senger
Column E: Staff Witness Farris
Column F: Staff Witness Farris
Column G: Staff Witness Senger
Column H: Page 3, herein

NORTHWESTERN PUBLIC SERVICE
South Dakota Gas Operations
Commission Staff Income Adjustments
Test Year Ended December 31, 1998

(A)	Consolidated Tax Savings (B)	Interest Synchro-nization (C)	(D)	(E)	(F)	(G)	(H)	Summary of Adjustments (I)
Operating revenue								
1. Gas sales revenue								$16,541
2. Transportation revenue								(19,410)
3. Other revenue								3,445
4. Total revenue	$0	$0	$0	$0	$0	$0	$0	$576
Operating expenses								
5. Cost of gas supply								12,882
6. MGP removal cost adjustment								474
7. Operating and maintenance								(585,888)
8. Depreciation and amortization								0
9. Taxes other than income								335
10. Federal income taxes	(182,672)	(150,570)						(121,571)
11. Rate case expense								(32,000)
12. Total operating expenses	($182,672)	($150,570)	$0	$0	$0	$0	$0	($725,768)
13. Net operating income - pro forma	$182,672	$150,570	$0	$0	$0	$0	$0	$726,344

Sources:
Column B: Page 4, herein
Column C: Page 5, herein

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Nekota Resources Pipeline Adjustment
Test Year Ended December 31, 1998

	(A)	(B)
1.	Rate of return	8.42%
2.	Federal income taxes on return	2.14%
3.	Property taxes	2.50%
4.	Fixed charge factor	13.06%
5.	Nekota Resources' original investment	$1,185,000
6.	Service period (years)	20
7.	Levelized fixed charge cost of service	$169,264
8.	Allocation to NWPS - South Dakota	62.50%
9.	NWPS's share of levelized cost	$105,790
12.	NEC's charges as filed	576,000
13.	Adjustment to affiliate charges	($470,210)

Sources:
Lines 1,2: Developed from Schedule 1, page 2
Line 3: NWPS's property tax/net plant ratio
Lines 5,6,8: NWPS's response to Staff request 7-01
15,000/24,000 MMBtu/d

Gas plant in service	51,039,201
Accumulated depreciation	15,287,364
Net plant in service	35,751,837
Property taxes - test year	909,733
Property tax/net plant ratio	2.5%

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Consolidated Tax Savings Adjustment
Test Year Ended December 31, 1998

	(A)	(B)	(C)
	Taxable income of affiliates w/ positive income		
1.	1996	$47,666,302	
2.	1997	29,809,381	
3.	1998	37,811,667	
4.	Three-year average	$38,429,117	
	Taxable losses of affiliates		
5.	1996	($25,343,132)	
6.	1997	(21,022,073)	
7.	1998	(11,876,670)	($11,876,670)
8.	Three-year average	($19,413,958)	
	Consolidated taxable income		
9.	Average (Line 4 - Line 8)	$19,015,158	
	NWPS-Gas		
10.	Average taxable income	3,069,276	
11.	Percent of Line 4		7.99%
12.	Share of taxable losses		$948,946
13.	South Dakota allocation (55%)		521,920
14.	Consolidated tax savings @ 35% FIT rate		$182,672

Sources
Lines 1-7,10: NWPS response to Staff Request No. 6-04
Line 10: Taxable income 1996 - $4,882,154; 1997 - $$5,425,049; 1998 - $(1,099,37
Line 13: 55% is SD Factor "F" from NWPS Exhibit (TPH-1), page 57

NORTHWESTERN PUBLIC SERVICE

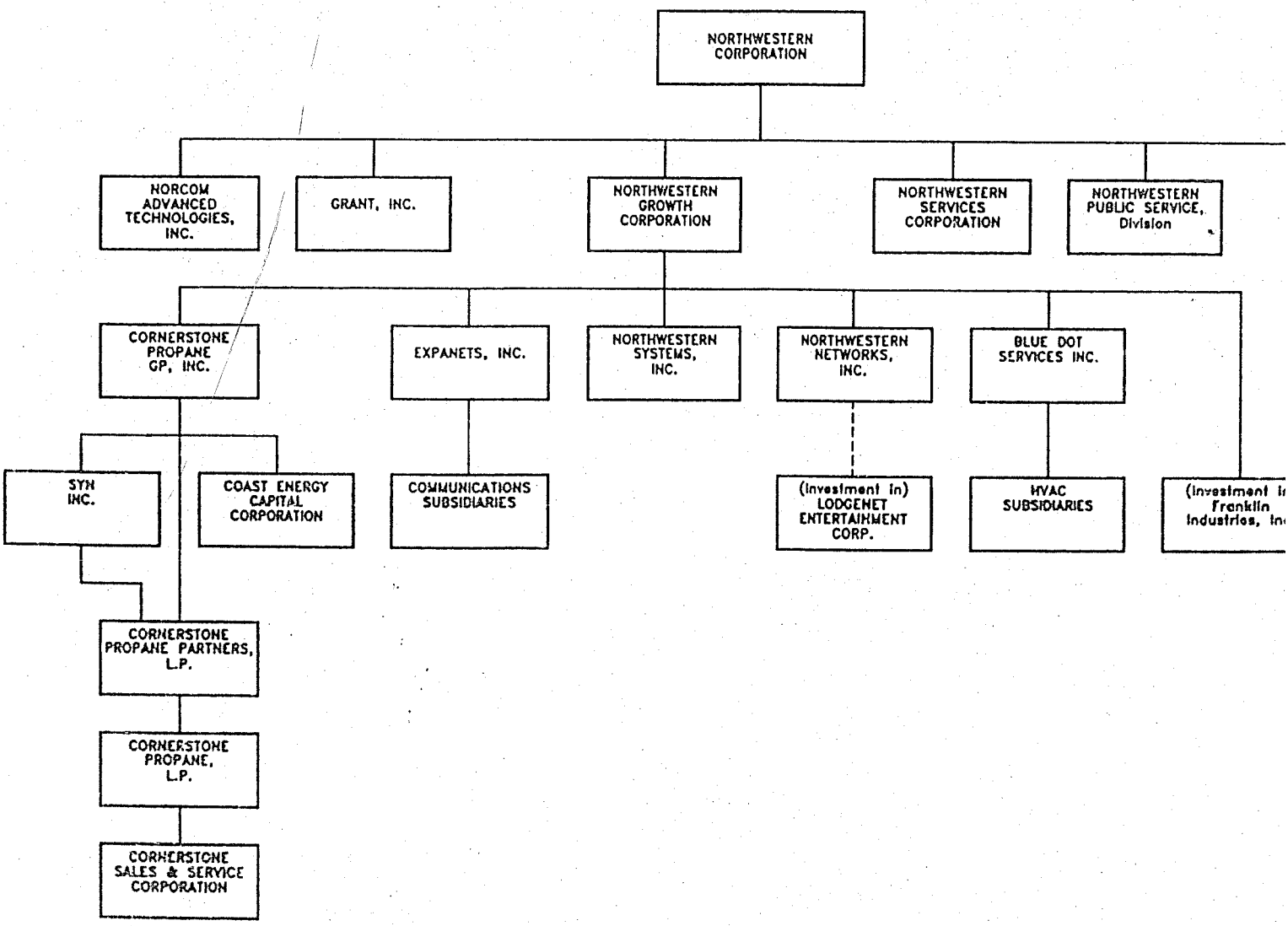
South Dakota Gas Operations
Interest Synchronization Adjustment
Test Year Ended December 31, 1998

(A)	(B)
1. Average rate base	$36,190,783
2. Weighted cost of debt	4.44%
3. Synchronized interest expense	$1,606,871
4. Interest expense as filed	1,176,672
5. Adjustment to interest expense	$430,199
6. Federal income tax adjustment	(150,570)
7. Net income adjustment	$150,570

Sources:
Line 1: Schedule 2, page 1
Line 2: Schedule 1, page 2
Line 4: NWPS Exhibit TPH-1, page 45

NorthWestern™

PARTNER ENTITIES



NorthWestern Public Service
Commission Staff Class Cost Analysis
Income Statement-Present Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Reference	Total Service Area	Residential
	(a)	(b)	(c)	(d)
1	Revenues:			
2	Gas sales and transportation revenues (non-gas cost)		11,796,032	7,570,923
3	Other revenues		366,742	137,498
4				
5	Total Revenues		12,162,774	7,708,421
6				
7	Expenses			
8	Operations & maintenance expenses		5,100,236	3,457,920
9	Depreciation & amortization expense		1,616,790	975,395
10	Taxes other than income taxes		974,192	587,722
11	MGP removal cost		1,310,866	790,836
12	Rate case expense		18,000	11,715
13				
14	Total Expenses		9,020,084	5,823,588
15				
16	Operating Income Before Income Taxes		3,142,690	1,884,833
17				
18	Federal and State Income Taxes		363,940	217,753
19				
20	Net Operating Income		2,778,750	1,667,080
21				
22				
23	Rate Base		36,190,782	21,754,370
24				
25				
26	Return on Rate Base		7.68%	7.66%
27				
28				
29	Return on Equity		8.69%	8.65%
30				
31	Federal and State Effective Tax Rate	35.00%		
32				
33	Capital Ratios			
34	Long-term debt	62.4896%		
35	Preferred stock & securities	0.7097%		
36	Common stock equity	36.8007%		
37				
38	Weighted Cost of Capital			
39	Long-term debt	4.4443%		
40	Preferred stock & securities	0.0363%		
41	Common stock equity	3.1975%		

NorthWestern Public Service
Commission Staff Class Cost Analysis
Income Statement-Required Rates
South Dakota Gas
Test Year Ended December 31, 1998

Line No.	Description	Reference	Total Service Area	Residential
	(a)	(b)	(c)	(d)
1	Revenues:			
2	Gas sales and transportation revenues (non-gas cost)		12,198,322	7,817,112
3	Other revenues		366,742	137,498
4				
5	Total Revenues		12,561,911	7,952,589
6				
7	Expenses:			
8	Operations & maintenance expenses		5,100,236	3,457,920
9	Depreciation & amortization expense		1,616,790	975,395
10	Taxes other than income taxes		974,192	587,722
11	MGP removal cost		1,310,866	790,836
12	Rate case expense		18,000	11,715
13				
14	Total Expenses		9,020,084	5,823,588
15				
16	Operating Income Before Income Taxes		3,541,827	2,129,001
17				
18	Federal and State Income Taxes		494,563	297,283
19				
20	Net Operating Income		3,047,264	1,831,718
21				
22				
23	Rate Base	0	36,190,782	21,754,370
24				
25				
26	Return on Rate Base		8.42%	8.42%
27				
28				
29	Return on Equity		10.70%	10.70%
30				
31	Federal and State Effective Tax Rate	35.00%		
32				
33	Capital Ratios			
34	Long-term debt	62.4896%		
35	Preferred stock & securities	0.7097%		
36	Common stock equity	36.8007%		
37				
38	Weighted Cost of Capital			
39	Long-term debt	4.4443%		
40	Preferred stock & securities	0.0363%		
41	Common stock equity	3.9394%		

NORTHWESTERN PUBLIC SERVICE

South Dakota Gas Operations
Development of Customer-Related Unit Cost
Test Year Ended December 31, 1998

	Residential	Small Commercial	Large Commercial
(A)	(B)	(C)	(D)
Customer-related gross plant in service			
1. Services	$7,041,484	$1,034,387	$449,422
2. Meters	2,632,135	580,026	699,956
3. Meter installations	966,910	213,071	257,127
4. Regulators	580,867	128,002	98,857
5. Regulator installations	376,737	83,019	64,117
6. Subtotal gross plant	$11,598,133	$2,038,505	$1,569,479
7. Accumulated depreciation	(3,474,113)	(610,615)	(470,123)
8. Accumulated deferred income taxes	(141,499)	(24,870)	(19,148)
9. Customer-related net plant	$7,982,521	$1,403,020	$1,080,208
Customer-related cost of service			
10. Rate of return @ 8.42%	671,865	118,088	90,918
11. Income taxes on return	170,826	30,025	23,116
Operating expenses			
12. Services	107,489	15,790	6,860
13. Meter and house regulators	173,646	38,265	46,177
14. Customer installations	(137,393)	(20,185)	(1,462)
Maintenance expenses			
15. Services	33,958	4,989	2,168
16. Meter and house regulators	56,809	12,519	15,108
17. Customer accounts expense (ex. uncollectibles	731,725	107,498	23,350
18. Customer service and info. expenses	690,023	101,374	22,021
19. Employee pensions and benefits	221,207	32,955	16,213
20. Depreciation expense	376,471	66,176	50,938
21. Property taxes	197,076	34,294	26,475
22. Customer-related cost of service	3,293,702	541,788	321,882
23. Number of annual bills (TPH-2, page 4)	400,847	58,889	4,264
24. Customer cost per bill	$8.22	$9.20	$75.49

Sources:
NWPS Exhibit (TPH-2) and Towers workpapers

NORTHWESTERN PUBLIC SERVICE
South Dakota Gas Operations
Workpapers to Customer Service Charge
Test Year Ended December 31, 1998

(A)	Residential (B)	Small (C)	Large (D)	Total (E)
Accumulated depreciation				
Gross plant for customer charge	11,598,133	2,038,505	1,569,479	
Total gross plant - Co. allocat of customer	15,591,962	2,740,466	2,109,931	
% Customer for customer charge	74.39%	74.39%	74.39%	
Depreciation reserve				
Direct South Dakota - customer	(4,342,812)	(763,299)	(587,677)	
Common - customer	(327,323)	(57,531)	(44,294)	
Total customer related dep. reserve	(4,670,135)	(820,830)	(631,971)	
Depreciation reserve for customer charge	(3,474,113)	(610,615)	(470,123)	
Accumulated deferred taxes, ITC - customer	(190,213)	(33,432)	(25,740)	
% Customer for customer charge	74.39%	74.39%	74.39%	
Deferred taxes for customer charge	(141,499)	(24,870)	(19,148)	
Operating expenses – services				
Mains and services Operating- Labor				152,401
Mains and services Operating- Other				274,148
Subtotal				426,549
Services as % of Mains and Services				30.51%
Services amount				130,140
Services allocation factors	82.595221%	12.133151%	5.271628%	100.000000%
Operating expenses - services	107,489	15,790	6,860	130,139
Pensions and Benefits				
Total customer O&M	1,656,257	260,250	114,222	
Total O&M excluding cost of gas	3,816,344	924,929	944,880	
Less: pensions and benefits	449,654	103,958	117,448	
O&M net of pensions and benefits	3,366,690	820,971	827,432	
Customer O&M as percent of net O&M	49.20%	31.70%	13.80%	
Customer pensions and benefits	221,207	32,955	16,213	
Depreciation expense				
Customer related gross plant	11,598,133	2,038,505	1,569,479	
Total distribution and production gross plant	22,896,830	8,044,842	7,024,008	
Percent of total that is customer-related	50.65%	25.34%	22.34%	
Total distribution and production dep. exp.	743,279	261,152	228,014	
Depreciation expense - customer related plant	376,471	66,176	50,938	
Property taxes				
Customer related net plant	7,982,521	1,403,020	1,080,208	
Total rate base	22,220,348	7,887,548	6,866,463	
Customer related as percentage of total	35.92%	17.79%	15.73%	
Property tax expense	548,653	192,771	168,309	
Customer related property taxes	197,076	34,294	26,475	

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
NORTHWESTERN PUBLIC SERVICE FOR)
AUTHORITY TO INCREASE RATES FOR) DOCKET NO. NG99-002
NATURAL GAS SERVICE)

TESTIMONY AND EXHIBIT
OF
BASIL L. COPELAND JR.

ON BEHALF OF
THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

September 24, 1999

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE

DOCKET NO. NG99-002

Testimony of Basil L. Copeland, Jr.

On Behalf of the
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

SECTION I: BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND TELEPHONE NUMBER.

A. My name is Basil L. Copeland, Jr.; my business address and telephone number are 14619 Corvallis Road, Maumelle, AR, 72113, (501)851-8604.

Q. WHAT IS YOUR OCCUPATION?

A. I am an economist, specializing in energy and utility economics, and a principal in Chesapeake Regulatory Consultants, Inc., 10025 Governor Warfield Parkway, Suite 301B, Columbia, MD, 21044, (301)596-3103.

Q. WERE YOU RETAINED BY THE COMMISSION STAFF IN THIS CASE?

A. Yes.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my education at Portland State College (1967-1969), New Mexico Institute of Mining and Technology (1969), and Oregon State University (1972-75). In 1974 I received a Bachelor of Science degree in Economics from Oregon State University, and in 1976 a Master of Science degree in Resource Economics (with a minor in Business Finance) from the same institution.

From August 1975 to February 1977, I was employed as a financial analyst and staff economist for the Arkansas Public Service Commission. From March 1977 to August 1978, I was employed in a similar position by the Iowa State Commerce Commission. In September of 1978 I went to work for the Attorney General of Arkansas in a U.S. Department of Energy-funded office of consumer services, with responsibility for economic analysis in electric utility

rate cases. While with the Attorney General, I assisted in the development of legislation that created the Arkansas Department of Energy. In July of 1979, soon after the Department was officially created, I was appointed Deputy Director for Forecasting. In that position, I directed a staff with broad responsibilities which included the development of an energy management information system for monitoring energy supply and demand in Arkansas, including comprehensive forecasts of energy demand by fuel source and sector.

I left the Arkansas Department of Energy in January 1981, and worked briefly as an independent consultant before joining the consulting firm of Hess and Lim, Inc., in April 1981. While employed by Hess and Lim, I served as a consultant on numerous rate cases before the FERC and various state utility commissions. I left Hess & Lim in October 1986 to join with two other consultants in the founding of Chesapeake Regulatory Consultants. I have testified or provided technical assistance in over 160 proceedings before the FERC, the FCC, and regulatory bodies in: Alabama, Arizona, Arkansas, California, Colorado, Georgia, Illinois, Iowa, Maine, Maryland, Montana, New Mexico, New York, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont, Washington State, West Virginia, and the District of Columbia. On four occasions I have been invited to appear on the program of the annual conference of Michigan State University's Institute of Public Utilities, and I have served as faculty for the Michigan State-NARUC summer training program for regulatory commission personnel. I have published numerous articles on a variety of utility issues, including articles or comments in **Land Economics, American Economic Review, Public Utilities Fortnightly, Journal of Business Research, Yale Journal on Regulation, Journal of Portfolio Management, Energy Law Journal** and the **Financial Analysts Journal**. My 1982 article in the **Financial Analysts Journal** on the equity risk premium received a Graham and Dodd award from the Financial Analysts Federation. I have also served as an academic referee for two academic journals where I reviewed articles on utility economics and finance. My article in the Spring 1991 issue of the **Energy Law Journal** ("Procedural Versus Substantive Economic Due Process for Public Utilities.") dealt with the constitutional standards for due process as applied to utility ratemaking under the celebrated **Hope** case, and undertook a comparative analysis and critique of the 1989 **Duquesne** decision. A list of publications is provided at the end of my testimony.

SECTION II: PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present evidence with respect to the cost of capital for Northwestern Public Service, a division of NorthWestern Corporation, and to express an opinion as to a fair and reasonable rate of return based upon that evidence. In developing a cost of capital for Northwestern Public Service, I have also made several adjustments to the capital structure in order to develop a capital structure applicable to the Applicant's utility operations.

Q. PLEASE DESCRIBE THE PROCEDURES YOU USED TO DETERMINE THE COST OF EQUITY.

A. I utilized two different methods to determine Northwestern's cost of equity: the traditional dividend cash flow (DCF) methodology, and non-constant growth dividend discount model (DDM) methodology. My application of these methods takes into account recent capital market conditions and how that impacts the determination of a fair rate of return on equity.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on the evidence presented below, I conclude that the current cost of equity capital for Northwestern Public Service is 9 to 10 percent. However, this cost of equity cannot be applied to the filed capital structure. The filed capital structure is inappropriate because it contains substantial investments in unregulated enterprises. Unless the capital structure is adjusted to remove the effect of these investments, utility ratepayers will indirectly subsidize NorthWestern Corporation's shareholders' equity return on its equity investment in these unregulated enterprises. I have taken the necessary steps to remove these investments from the capital structure. Since this is a gas rate case, I have also adjusted the utility capital structure to remove pollution control bonds from the capital structure. This results in a Northwestern Public Service capital structure of approximately 62.5 percent long-term debt, 0.7 percent preferred stock, and 36.7 percent common stock equity. As explained more thoroughly in my testimony below, I am recommending a return on equity of approximately 10.7 percent in recognition of the higher financial risk associated with such a low equity ratio. This 10.7 percent recommend return is applicable only if my capital structure adjustments are accepted. If my capital structure adjustments are not accepted, then my recommended rate of return on equity is only

9 to 10 percent. Based on my recommended capital structure, the recommended overall rate of return is 8.4167%. The derivation of this return is shown on Exhibit____(BLC-1), Schedule 1.

SECTION III: IMPACT OF RECENT MARKET CONDITIONS

Q. PLEASE DESCRIBE RECENT CAPITAL MARKET CONDITIONS FOR UTILITIES.

A. During the late 1970's and early 1980's interest rates rose to historic highs, and utility stock prices generally traded below book value, indicating that expected and earned book returns were below the required rate of return. In the mid-1980's, however, with a significant reduction in the actual and expected rate of inflation, interest rates fell dramatically, and utility stock prices rebounded to levels well above book value, trends which continued into the early 1990's. Long-term interest rates fell to 20 year lows in late 1993, indicating the most favorable market conditions for utilities in more than two decades. Long-term interest rates began to rise again in late 1993, and rose through most of 1994, but remained at levels not experienced since the mid-1970's, and throughout the 1990's utility stocks have generally traded at prices well above book value. During the past two years, however, capital costs have again fallen significantly, and are presently at lows not last seen since the early to mid 1960's.

Q. HOW DOES THIS IMPACT THE DETERMINATION OF A FAIR RETURN ON EQUITY?

A. The price of utility common stock and the cost of utility common equity are closely tied to interest rate levels. As interest rates fall, the cost of utility common stock falls, and utility stock prices rise. In the low inflation, low interest rate environment of current capital markets, utility stocks are selling significantly above book value.

Q. BASED ON YOUR EDUCATION AND EXPERIENCE, OF WHAT SIGNIFICANCE IS THE FACT THAT UTILITY STOCKS ARE SELLING AT PRICES SIGNIFICANTLY ABOVE BOOK VALUE?

A. Prices significantly above book value indicate that allowed and earned rates of return have not declined commensurately with declines in the cost of capital. In other words, investors have been earning returns above the cost of capital, and have capitalized this excess return in the form of market prices substantially above book value. Another way to look at it: declines in the cost of capital have not been passed on to ratepayers.

Q. GENERALLY, HOW DO THESE MARKET TRENDS RELATE TO YOUR DETERMINATION OF THE COST OF EQUITY CAPITAL FOR NORTHWESTERN?

A. A principal method for determining the cost of equity capital and fair rate of return on equity capital for utility common stock is the "discounted cash flow" (DCF) methodology. The DCF methodology is a market-based method of determining the cost of equity, and will reflect changing market conditions, principally through the dividend yield portion of the DCF rate of return. In view of the significant improvement in capital market conditions in recent years, a DCF analysis of the cost of equity for Northwestern should indicate a much lower cost of equity capital than was the case in the 1980's or early 1990's.

SECTION IV: PRESENTATION OF EVIDENCE

A. Discounted Cash Flow (DCF) Methodology

Q. PLEASE EXPLAIN THE BASIC THEORY UNDERLYING THE USE OF THE DCF METHODOLOGY TO DETERMINE THE COST OF COMMON EQUITY.

A. According to the DCF theory the investor's required return on common stock equity equals the dividend yield on the stock plus the expected rate of growth in the dividend. This relationship is commonly represented mathematically as:

$$k = D/P + g$$

where **k** is the cost of equity capital (the investor's required return), **D/P** is the dividend yield (the dividend divided by market price), and **g** is the expected rate of growth in the dividend. Depending on the nature of the assumptions and mathematical procedures employed in the derivation of the model, the dividend yield portion of the total return is variously represented as D_0/P_0 or D_1/P_0 where D_0 and D_1 represent the "current dividend" and the "next period dividend," respectively. Depending further on what is assumed about the frequency of payout and the compounding of intra-period retained earnings, as an annual yield D_0/P_0 will tend to understate the effective yield, while D_1/P_0 will tend to overstate it. A valid conceptual argument can be made for using an average of the two, sometimes presented in the form $D_0(1+.5g)/P_0$. This is the method I have used to compute the dividend yield component of the DCF return.

Q. WHAT STEPS ARE INVOLVED IN IMPLEMENTING THE DCF METHODOLOGY?

A. The principal steps in implementing the DCF approach are the selection of a sample of companies to which to apply the method, and the selection of measures of expected growth.

Q. WHAT SAMPLE OF COMPANIES DID YOU USE, AND HOW DID YOU DEVELOP THE SAMPLE?

A. I used a sample of combination gas and electric utilities with a Value Line Safety Rank of 2, the

same Safety Rank assigned by Value Line to NorthWestern Corporation. The sample, and selected financial risk characteristics for the firms in the sample, is presented in Exhibit____(BLC-1), Schedule 2. Based on the indicated financial risk criteria — the Value Line "Safety Rank," "Earnings Predictability," stock "beta" coefficient, and "Financial Strength" rating — the sample is reasonably comparable in risk to NorthWestern. From the standpoint of financial theory, the most meaningful risk measure is the stock "beta" coefficient (lower means less risk), and NorthWestern's beta is 0.55, the same as the sample median. Thus this sample should provide a reasonable basis for determining a fair rate of return for NorthWestern's shareholders on its utility equity.

Q. WHAT DATA DID YOU EXAMINE IN ORDER TO DETERMINE THE INVESTOR EXPECTED GROWTH RATE FOR YOUR DCF ANALYSIS?

A. To determine investor expectations with respect to future dividend growth, I examined IBES (Institutional Brokers Estimate System) earnings per share (EPS) projections, the current "% Retained to Common Equity" reported by Value Line, and Value Line growth projections for earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS), giving me a potential total of five growth projections for each company.[1] (Not all companies in the sample had available data for all five growth parameters.) I developed DCF rates of return using both the mean and median growth rates for each company.

Q. PLEASE DESCRIBE THE RESULTS.

A. The results are shown in the last two columns of Exhibit____(BLC-1), Schedule 2. For the sample as a whole, the average DCF rate of return was 9.18 percent, consisting of a dividend yield of 5.23 percent, and an average expected growth rate of 3.95 percent. Also shown on Exhibit____(BLC-1), Schedule 2, is a comparison for NorthWestern specifically. The resulting average DCF return for NorthWestern was 14.45 percent. Though I show the comparison data for NorthWestern, in my opinion this is not a reasonable or reliable estimate of the cost of equity for Northwestern Public Service. Taken as a whole, the data presented in Exhibit____(BLC-1), Schedule 2, indicate a DCF cost of equity of 9.2 percent for combination utilities comparable to NorthWestern's utility operations.

Q. PLEASE EXPLAIN WHY THE DCF RATE OF RETURN SHOWN FOR NORTHWESTERN IS

[1] IBES — or I/B/E/S — is a service of I/B/E/S International, Inc. consisting of a survey of institutional brokerage earnings forecasts for common stock.

NOT REASONABLE OR RELIABLE AS AN ESTIMATE OF THE APPROPRIATE COST OF EQUITY FOR NORTHWESTERN PUBLIC SERVICE?

A. There are several reasons. First, it is a "sample of one" estimate. A single estimate such as this is never as reliable as the average or median of a larger sample. Second, it represents an estimate of the cost of equity for NorthWestern Corporation as a whole, and not specifically its utility operations. While many utilities now have some non-utility operations, NorthWestern Corporation's utility operations now provide it with less revenues than its non-utility operations. The fair rate of return is one commensurate with the return that could be earned on other investments of comparable risk. This is the return indicated by the average or median cost of equity for the sample group, not the return indicated for NorthWestern Corporation. Finally, the unusually high rate of earnings growth shown for NorthWestern Corporation indicates that NorthWestern Corporation's cost of equity may not be consistent with the underlying requirements of the constant growth DCF model. This is in fact the case, as I will show with the results from the non-constant growth dividend discount model later in my testimony.

Q. **IS A 9.2 PERCENT ESTIMATE OF THE COST OF EQUITY A REASONABLE RATE OF RETURN ON EQUITY IN RELATION TO CURRENT BOND YIELDS?**

A. Yes, it is. For the six months ending August 31, 1999, the average yield on long term treasury bonds was 5.8 percent, while the average yield on Moody's A rated bond index was 7.6 percent. Because of the "defensive" characteristic of utility stocks — their prices fall less than the market as a whole when the market slumps — they are priced somewhat like bonds and normally require only a modest risk premium over bonds compared to other common stocks. A 9.2 percent cost of equity for utility stocks yields a fair and reasonable risk premium relative to the yields on these bond instruments, especially in the current low inflation, low interest rate, capital market environment.

B. Dividend Discount Model (DDM) Methodology

Q. **WHAT ARE THE DIVIDEND DISCOUNT MODELS.**

A. Dividend discount models are more general forms of the DCF methodology which embody less restrictive assumptions than the traditional methodology. The traditional methodology, sometimes referred to as the "constant growth" or "sustainable growth" model, assumes that dividends, earnings, book value per share, and share price all grow at the same uniform rate of growth. While this is rarely the case in actuality, it is not an unreasonable assumption if the

differences are small, a condition which implicitly requires a relatively constant dividend payout ratio.

Q. WHY DID YOU USE A DIVIDEND DISCOUNT MODEL IN ADDITION TO THE MORE TRADITIONAL DCF MODEL?

A. Where dividend payout ratios are expected to trend upward or downward over extended periods of time, use of five-year growth projections of the type published by IBES, Value Line, or other investment services in a constant growth form of the DCF model can produce distorted and unreliable results. Currently, payout ratios are trending downward. Multiple-period dividend discount models provide more reliable and accurate measures of the expected DCF return under such conditions.

Q. PLEASE EXPLAIN IN FURTHER DETAIL HOW THE MULTIPLE PERIOD DIVIDEND DISCOUNT MODEL IS DERIVED.

A. Multiple period dividend discount models are based on finite horizon DCF models of the form:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} + \frac{P_t}{(1+k)^t}$$

where

$$P_t = \frac{D_t(1+g)}{(k-g)}$$

Here t is a finite time period, at the end of which the stock would be sold for P_t.. By postponing the period of constant growth to some finite point of time in the future, dividends can be projected during the interim that follow any pattern consistent with expected earnings growth and dividend payout ratios.

Q. BASED ON YOUR EDUCATION AND EXPERIENCE, ARE SUCH MODELS ACTUALLY USED BY INVESTORS TO DETERMINE EXPECTED RETURNS?

A. Yes, they are. Such models are used by firms such as Prudential-Bache and Merrill Lynch to develop expected returns, and are presented along with constant growth models in standard textbooks.

Q. PLEASE DESCRIBE IN FURTHER DETAIL YOUR IMPLEMENTATION OF THIS METHODOLOGY.

A. The basic data employed in my implementation of this methodology is presented in Exhibit____(BLC-1), Schedule 3. The basic input data consists of the current dividend yield, an EPS projection for 1999, the current IBES EPS growth projection, a projection of long-term growth into perpetuity, and retention ratios for 1999, 2003, and 2018. The DDM analysis assumes that earnings grow from 1999 to 2003 at the indicated IBES growth rate, and at the long-term growth rate thereafter. The period from 2003 to 2018 is a transition period during which the payout ratio changes from the value projected by Value Line in the year 2003 to a common value for all companies in the sample in the year 2018. Constant growth assumptions — long term growth of 4.5%, and a retention ratio of 0.40 — apply after the year 2018, allowing the determination of a terminal share price for the year 2018. These long-term conditions after 2018 are applied to all the companies in the sample. Having generated a series of cash flows, the model generates an expected return, k, by solving the following equation:

$$0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} + \frac{P_t}{(1+k)^t} - P_0$$

The solution to this equation is the value of k which makes the right hand side of the equation zero. This can only be done by trial and error, but there are computer algorithms for finding the solution to such formulas automatically. The DDM returns shown on Exhibit____(BLC-1), Schedule 3, were developed using the "solver" routine in an Excel spreadsheet.

Q. PLEASE SUMMARIZE THE RESULTS AND COMMENT ON THEIR SIGNIFICANCE.

A. The mean DDM return for the combination utility company sample was 9.12 percent, and the median DDM return was 9.23 percent. These results corroborate closely the constant growth DCF returns presented in Exhibit____(BLC-1), Schedule 2. More notable, perhaps, is the 9.10 percent DDM return for NorthWestern Corporation, which corroborates my earlier suggestion that the constant growth DCF model does not produce reliable estimates of the cost of equity for NorthWestern.

D. Summary of Opinion on Cost of Equity and Fair Rate of Return on Equity.

Q. PLEASE SUMMARIZE YOUR OPINION REGARDING NORTHWESTERN PUBLIC SERVICE'S COST OF EQUITY AND FAIR RATE OF RETURN ON EQUITY.

A. Based on the results shown on Schedules 2 and 3 of my exhibit, it is my opinion that the cost of equity for utilities comparable in risk to Northwestern Public Serivce is presently about 9.0

to 10.0 percent.

E. Capital Structure

Q. **PLEASE EXPLAIN WHY YOU DID NOT ACCEPT THE FILED CAPITAL STRUCTURE.**

A. Because of an aggressive program of mergers and acquisitions, the recently renamed NorthWestern Corportion is no longer primarily a combination gas & electric utility. In 1998, revenues from NorthWestern Corporation's electric and natural gas operations comprised just 12.2 percent of its total revenues. In addition to its electric and gas utility operations, NorthWestern Corportion holds interests in Cornerstone Propane Partners, L.P. (NYSE: CNO), the nation's fourth largest retail propane distributor; Expanets, Inc., a national provider of integrated communications and data solutions and network services; and Blue Dot Services, Inc., a national provider of air conditioning, heating, plumbing and related services. Revenues from propane sales accounted for 64.6 percent of the Corporation's total revenues, while combined revenues from HVAC and communications accounted for 21.4 percent of the Corporation's total revenues. The consolidated capital structure filed by the Applicant contains the combined investment of all these varied enterprises. With over 85 percent of the Applican's revenues now coming from non-utility operations and investments, it is important to insure that the consolidated capital structure does not result in cross-subsidization of the return earned by the Applicant on its non-utility investments from the return granted on its utility investment.

Q. **PLEASE EXPLAIN HOW SUCH CROSS-SUBSIDIZATION TAKES PLACE.**

A. When non-utility investment is consolidated with utility investment, it typically raises the equity ratio in the capital structure, and reduces the debt ratio, resulting in a higher overall rate of return passed on to utility ratepayers. Indirectly, what is taking place is that utility ratepayers are being deprived of the full use of utility debt, which has a much lower cost rate than equity. At the same time, the utility debt that ratepayers are deprived of inures to the benefit of the Corporation's non-utility investment, "leveraging" the return on equity in non-utility investment, i.e. resulting in a higher return on equity in non-utility investment than would be earned otherwise.

Q. **CAN YOU ILLUSTRATE THIS WITH A SIMPLE EXAMPLE?**

A. Yes, I can. Assume that a utility has $ 100 million of investment, financed with 60 percent debt, at a cost of 8 percent, and 40 percent equity at a cost of 10 percent. The utility's capital

structure and overall cost of capital is:

Utility Capital Structure and Rate of Return				
Source	Amount	% of Total	Cost	Wtd Cost
Long-Term Debt	60,000,000.00	60.00%	6.00%	3.60%
Common Equity	40,000,000.00	40.00%	10.00%	4.00%
Total	100,000,000.00	100.00%		7.60%

Now assume that a non-utility company has the following capital structure and capital costs:

Non-Utility Capital Structure and Rate of Return				
Source	Amount	% of Total	Cost	Wtd Cost
Long-Term Debt	40,000,000.00	40.00%	6.00%	2.40%
Common Equity	60,000,000.00	60.00%	10.00%	6.00%
Total	100,000,000.00	100.00%		8.40%

The only difference between these two is in the relative amounts of debt and equity. But because the non-utility has more equity than the utility, its overall cost is higher. Now let's "merge" the two and create a "consolidated capital structure."

Consolidated Capital Structure and Rate of Return				
Source	Amount	% of Total	Cost	Wtd Cost
Long-Term Debt	100,000,000.00	50.00%	6.00%	3.00%
Common Equity	100,000,000.00	50.00%	10.00%	5.00%
Total	200,000,000.00	100.00%		8.00%

Observe how the consolidated capital structure is a "blend" of the two overall weighted average costs. Whereas the overall weighted average cost of the utility capital structure is 7.40 percent, the overall weighted average cost of the consolidated capital structure is 8.00 percent.

Q. WHAT HAPPENS WHEN THE RATE OF RETURN FROM THE CONSOLIDATED COST OF CAPITAL IS USED FOR A RATE OF RETURN ON UTILITY INVESTMENT?

A. The actual cost of utility capital in the preceding example remains 7.60 percent. If the weighted

cost of capital from the consolidated capital structure of 8.00 percent is allowed on the utility investment, the difference 0.40 percent, accrues to the benefit of the merged entity's shareholders as an excess return on equity.

Q. IS THIS HYPOTHETICAL SIMILAR TO THE FACTS OF THIS CASE?

A. Yes, it is. The non-utility components of the consolidated capital structure have been capitalized with much less debt than Northwestern Public Service. Consequently, when they are merged into a consolidated capital structure, the effect is to raise the equity ratio and lower the debt ratio which NorthWestern Corporation seeks to apply to its utility operations. The effect is precisely that illustrated in the preceding hypothetical example.

Q. HOW CAN THIS EFFECT BE PREVENTED?

A. To prevent this effect, the capital structure must reflect only utility investment.

Q. IS THAT WHAT IS REPRESENTED BY THE CAPITAL STRUCTURE SHOWN ON YOUR EXHIBIT____(BLC-1), SCHEDULE 1?

A. Yes, it is.

Q. HOW DID YOU DEVELOP THIS CAPITAL STRUCTURE?

A. I developed this capital structure on the basis of information provided in response to the Commission Staff's Second Data Request, No. 2-54, which requested a reconciliation between the filed consolidated capital structure and a capital structure for Northwestern Public Service based on its 1998 FERC Form 1. With one exception, the capital structure based on the FERC Form 1 is "purged" of the substantial non-utility investments reflected in the consolidated capital structure, and thus more nearly represents the true and actual capital structure of the Company's utility operations.

Q. WHAT IS THE EXCEPTION TO WHICH YOU REFER?.

A. The Form 1 capitalization still contains a substantial amount of investment in non-utility operations, in particular, investment in Northwestern Growth Corporation. Northwestern Growth Corporation is the entity through which Northwestern Corporation acquired its investment in Blue Dot Services, Inc., and other non-utility investments. As a matter of fundamental ratemaking principle, this non-utility investment should be eliminated from equity. Its inclusion in the utility capital structure is essentially an extreme example of the problem illustrated in the above hypothetical example, because it represents non-utility investment funded wholly by equity. So I have removed it from the capital structure shown on my Schedule 1.

Q. HAVE YOU MADE ANY OTHER CHANGES FROM THE CAPITAL STRUCTURE BASED ON THE FERC FORM 1?

A. Yes. I have not included pollution control debt in the capital structure. That debt should be allocated completely to the benefit of electric customers. This is a gas rate case.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE CAPITAL STRUCTURE.

A. Starting with the FERC Form 1 capital structure, I adjusted it to remove the equity investment in Northwestern Growth Corporation, and did not include any pollution control bonds in the debt component of the capital structure. The resulting capital structure is 62.4896 percent long-term debt, 0.7097 percent preferred stock, and 36.8007 percent common equity.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE RETURN ON EQUITY TO ALLOW FOR THE EFFECT OF YOUR CAPITAL STRUCTURE ON RISK.

A. Removing Northwestern Growth Corporation from equity had the effect of reducing the equity ratio from 45.5978 percent to 36.8007 percent. An adjustment downward in the equity ratio of this magnitude creates a significant increase in the financial risk attributable to leverage. To offset this increase in financial risk, I increased the rate of return on equity to 10.6957 pe cent. This higher return on equity results in the same overall rate of return as would a 10 percent rate of return on equity on a capital structure of 45.5978 percent equity. By holding the overall rate of return constant, I've accounted for the increased financial risk associated with increased leverage. It is important to observe that this 10.6957 percent return on equity recommendation is applicable only to a capital structure with 36.8007 percent equity. If my recommended capital structure is not accepted, the rate of return on equity should not be adjusted for financial risk, and the appropriate rate of return on equity is my estimate of the cost of equity, i.e. 9 to 10 percent.

Q. DOES THAT COMPLETE YOUR TESTIMONY AT THE PRESENT TIME?

A. Yes, it does, except for the list of publications which follows.

Publications
of
Basil L. Copeland, Jr.

"Double Leverage One More Time," ***Public Utilities Fortnightly***, August 18, 1977, 19-24.

"Alternative Cost of Capital Concepts In Regulation." ***Land Economics*** 54 (August 1978): 348-61

"Estimates of the Cost of Equity for Public Utilities, 1971-1976." ***Journal of Business Research*** 7 No. 1 (1979): 9-17.

"The Cost of Equity Capital: A Model for Regulatory Review." In **Issues in Public Utility Regulation**, edited by Harry M. Trebing, 342-66. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1979.

"Capacity Planning, Reliability, and Outage Costs in Electricity Supply: Comments." In **Challenges for Public Utility Regulation in the 1980's**, edited by Harry M. Trebing, 511-516. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1981.

"Inflation, Interest Rates, and Equity Risk Premia." ***Financial Analysts Journal*** (May/June 1982): 32-43.

"Do Stock Prices Move Too Much to be Justified by Subsequent Changes in Dividends? Comment." ***American Economic Review*** 73 No. 1 (1983): 234-35.

"Inflation, Monetary Policy, and the Equity Risk Premium." In **Regulatory Reform: The State of the Regulatory Art, Emerging Concepts and Procedures** edited by J. Rhoads Foster, 183-201. Washington: Institute for Study of Regulation, 1984.

"Ratemaking Treatment of Excess Capacity: Reconciling Regulation with Consumer Sovereignty." In **Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing** edited by Patrick C. Mann and Harry M. Trebing, 407-40. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1984.

"Bailing Out Public Utilities with Troubled Nuclear Power Plants: Who wins, Who Loses?" In The **Impact of Deregulation and Market Forces on Public Utilities: The Future Role of Regulation** edited by Patrick C. Mann and Harry M. Trebing, 371-91. East Lansing: Michigan State University, Graduate School of Business Administration, Institute of Public Utilities, 1985.

"Price Theory and Telecommunications Regulation: A Dissenting View," with A. Severn. ***Yale Journal on Regulation*** 3 No. 1 (Fall 1985): 53-85.

"Capital Gains Taxes After Tax Reform," with Alan K. Severn. ***Journal of Portfolio Management*** 13 No. 3 (Spring 1987): 69-75.

"Escape from the Black Hole of FERC: A Proposal to Restore ***Pike*** Prudence Review," with Robert E. Johnston. ***The Electricity Journal*** 2 No. 4 (May 1989): 12-25.

"Telecommunications Regulation - The Continuing Dilemma: Commentary." In **Public Utility Regulation, The Economic and Social Control of Industry**, edited by Kenneth Nowotny, David B. Smith, and Harry M. Trebing, 131-36. Boston: Kluwer Academic Publishers, 1989.

"Procedural vs. Substantive Economic Due Process for Public Utilities," with Walter Nixon. ***Energy Law Journal*** 12 No. 1 (Spring 1991): 81-110.

BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	DOCKET NO. NG99-002

EXHIBIT
OF
BASIL L. COPELAND JR.

ON BEHALF OF
THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

September 24, 1999

EXHIBIT____(BLC-1)
SCHEDULE 1

Northwestern Public Service
Northwestern Public Service Company Cost of Capital
December 31, 1998

Line No.	Source	Reference	Amount	% of Total	Cost	Wtd. Cost
	A	B	C	S	E	F
1	Long-Term Debt	Line 14	330,206,000	62.4896%	7.1121%	4.4443%
2	Preferred Stock		3,750,000	0.7097%	5.1133%	0.0363%
3	Common Stock Equity	Line 7	194,461,189	36.8007%	10.6957%	3.9361%
4			528,417,189	100.0000%		8.4167%
	Common Stock Equity Detail					
5	Per Books Common Stock Equity		279,909,000			
6	Less: Equity in Northwestern Growth Corp.		(85,447,811)			
7	Total Utility Common Stock Equity		194,461,189			
	Long-Term Debt Detail					
	First Mortgage Bonds					
8	7.000% Series		55,000,000		7.0000%	3,850,000
9	6.990% Series		20,000,000		6.9900%	1,398,000
10	6.950% Series		105,000,000		6.9500%	7,297,500
11	7.100% Series		60,000,000		7.1000%	4,260,000
	Capital Trust					
12	8.125% Series		33,505,000		7.5300%	2,522,927
	Subdebentures					
13	7.200% Seriesl		56,701,000		7.3300%	4,156,183
14	Total Long-Term Debt		330,206,000		7.1121%	23,484,610

Northwestern Public Service Company
Selected Financial Risk Characteristics and DCF Rate of Return Analysis
Combination Gas & Electric Utilities — Value Line Safety Rank 2

Company Name	Ticker Symbol	Safety Rank	Earnings Pred.	Beta	Financial Strength	Current Dividend	Six-Month Avg Price	Dividend Yield	IBES Proj.	VL EPS Proj.	VL DPS Proj.	VL BVPS Proj.	% Ret. to Common	Mean Growth	Median Growth	DCF Return w/Mean	DCF Return w/Median
Alliant Energy	LNT	2			B++	2.00	28.604	6.96	2.0	4.2	0.4	2.3	2.5	2.3	2.3	9.25	9.27
Central Hudson	CNH	2	95	0.50	A	2.16	39.787	5.44	1.0	1.9	0.4	2.5	3.0	1.8	1.9	7.20	7.33
Cinergy	CIN	2	55	0.55	A	1.80	30.758	5.89	5.0	1.3	1.4	4.3	4.0	3.2	4.0	9.09	9.89
Constellation Energy Group	CEG	2	60	0.55	B++	1.68	29.973	5.62	4.0	3.1	0.5	3.2	4.0	3.0	3.2	8.59	8.79
Energy East Corporation	NEG	2	80	0.60	A	0.84	26.612	3.22	8.0	4.4	4.0	3.2	6.5	5.2	4.4	8.42	7.59
L&G Energy Corp.	LGE	2	60	0.55	B++	1.25	22.132	5.72	5.0	4.4	2.6	5.7	6.5	4.8	5.0	10.55	10.72
MDU Resources	MDU	2	85	0.55	A	0.82	22.857	3.66	7.5	6.6	4.0	6.2	6.5	6.2	6.5	9.83	10.16
Montana Power Co.	MTP	2	90	0.45	A	0.80	34.656	2.30	6.7	4.1	0.6	5.1	5.0	4.3	5.0	6.60	7.30
New Century Energies	NCE	2			A	2.32	37.202	6.27	5.0	2.7	1.1	4.1	4.0	3.4	4.0	9.65	10.27
PECO Energy Company	PE	2	60	0.65	B++	1.00	44.417	2.27	6.5	6.6	1.7	16.9	13.5	9.0	6.6	11.32	8.87
P.S. Enterprise Group	PEG	2	75	0.50	A	2.16	40.214	5.39	3.0	2.2	0.6	3.3	4.0	2.6	3.0	8.01	8.39
Puget Sound Energy	PSD	2	70	0.55	B++	1.84	24.419	7.54	3.9	2.2	0.0	1.0	1.5	1.7	1.5	9.26	9.04
Rochester Gas & Electric	RGS	2	70	0.50	A	1.80	26.564	6.78	1.5	1.4	0.0	2.1	3.0	1.6	1.5	8.38	8.28
St. Joseph Light and Power	SAJ	2	75	0.45	A	1.00	20.577	4.95		11.6	3.7	4.6	6.0	6.5	5.3	11.44	10.25
Wisconsin Energy	WEC	2	35	0.50	A	1.56	24.188	6.47	3.9	6.3	0.6	4.0	4.0	3.7	4.0	10.17	10.45
	Mean	2	70	0.53				5.23	4.50	4.20	1.45	4.55	4.93	3.95	3.87	9.18	9.11
	Median	2	70	0.55	A			5.62	4.50	4.13	0.61	3.96	4.00	3.38	4.00	9.25	9.04
Northwestern Corporation	NOR	2	65	0.55	B++	1.05	25.353	4.28	12.0	14.0	6.6	12.2	6.0	10.2	12.0	14.45	16.28

Sources: Value Line ; Compuserve PRISTATS, MQDATA.

EXHIBIT___(BLC-1)
SCHEDULE 2

EXHIBIT____(BLC-1)
SCHEDULE 3

Northwestern Public Service Company
DCF Rate of Return Analysis Using Dividend Discount Model (DDM)

Company	Inputs:							Output:
	Divdend Yield	1999 EPS	IBES Growth	Long-Term Growth	Retention Ratios 1999	2003	2010	DDM Return
Alliant Energy	6.96%	2.20	2.00%	4.50%	0.09	0.23	0.40	9.23%
Central Hudson	5.44%	2.85	1.00%	4.50%	0.24	0.29	0.40	8.51%
Cinergy	5.89%	2.60	5.00%	4.50%	0.31	0.30	0.40	9.99%
Constillation Energy Group	5.62%	2.35	4.00%	4.50%	0.29	0.36	0.40	9.23%
Energy East Corporation	3.22%	1.65	8.00%	4.50%	0.49	0.50	0.40	8.45%
L&G Energy Corp.	5.72%	1.85	5.00%	4.50%	0.32	0.38	0.40	9.72%
MDU Resources	3.66%	1.50	7.50%	4.50%	0.45	0.51	0.40	8.61%
Montana Power Co.	2.30%	1.25	6.70%	4.50%	0.36	0.45	0.40	6.74%
New Century Energies	6.27%	3.20	5.00%	4.50%	0.28	0.32	0.40	10.05%
PECO Energy Company	2.27%	3.00	6.50%	4.50%	0.67	0.73	0.40	8.05%
P.S. Enterprise Group	5.39%	2.90	3.00%	4.50%	0.26	0.31	0.40	8.82%
Puget Sound Energy	7.54%	1.90	3.90%	4.50%	0.03	0.12	0.40	10.04%
Rochester Gas & Electric	6.78%	2.35	1.50%	4.50%	0.23	0.28	0.40	10.84%
St. Joseph Light and Power	4.95%	1.25	11.60%	4.50%	0.20	0.42	0.40	9.20%
Wisconsin Energy	6.47%	1.90	3.90%	4.50%	0.18	0.36	0.40	9.25%
Mean					0.29	0.37		9.12%
Median					0.28	0.36		9.23%
Northwestern Corporation	4.28%	1.55	12.00%	4.50%	0.32	0.50	0.40	9.10%

BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	DOCKET NO. NG99-002

AFFIDAVIT
OF
BASIL L. COPELAND JR.

I, Basil L. Copeland Jr., certify that the preceding Testimony and Exhibit of Basil L. Copeland Jr. was prepared by me or under my direct supervision, and if asked the questions therein my answers and responses would as shown and are true and correct to the best of my information, knowledge and belief.

Basil L. Copeland Jr.

Subscribed and sworn to before me this 23th day of September, 1999.

NOTARY PUBLIC

My Commission expires: 3/5/2000



South Dakota
Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

Capitol Office
Telephone (605)773-3201
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Relay South Dakota
1-800-877-1113

Internet Website
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♦

Jim Burg
Chairman
Pam Nelson
Vice-Chairman
Laska Schoenfelder
Commissioner

William Bullard Jr.
Executive Director

Harlan Best
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Leni Healy
Camron Hoseck
Lisa Hull
Dave Jacobson
Katie Johnson
Bob Knadle
Delaine Kolbo
Charlene Lund
Terry Norum
Gregory A. Rislov
Keith Senger
Rolayne Ailts Wiest

♦

September 24, 1999

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 575-1

Re: In the Matter of the Application of NorthWestern Public Service for Authority to Increase Rates for Natural Gas Service
Docket NG99-002

Dear Mr. Bullard

Enclosed for filing you will find the originals of Testimony and Exhibits of Lavid A. Jacobson, Testimony of Martin C. Bettman, Testimony and Exhibits of Michele M. Farris, Testimony and Exhibits of Keith A. Senger, Testimony and Exhibit of Basil L. Copeland Jr., and Testimony of Robert G. Towers in the above captioned matter.

Very truly yours,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

KEC:dk
Enc.



South Dakota
Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

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Lisa Hull
Dave Jacobson
Katie Johnson
Bob Knadle
Delaine Kolbo
Charlene Lund
Terry Norum
Gregory A. Rislov
Keith Senger
Rolayne Ailts Wiest

September 24, 1999

Mr. Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service
600 Market Street West
Huron, SD 57350

Mr. Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street S.E.
Huron, SD 57350

Re: In the Matter of the Application of NorthWestern Public Service for Authority to Increase Rates for Natural Gas Service
Docket NG99-002

Dear Sirs:

Enclosed each of you will find a copy of Testimony and Exhibits of David A. Jacobson, Testimony of Martin C. Bettman, Testimony and Exhibits of Michele M. Farris, Testimony and Exhibits of Keith A. Senger, Testimony and Exhibit of Basil L. Copeland Jr., and Testimony of Robert G. Towers in the above captioned matter. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

KEC:dk
Enc.

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

RECEIVED
SEP 24 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

NORTHWESTERN PUBLIC SERVICE
DOCKET NO. NG99-002

TESTIMONY & EXHIBITS OF DAVID A JACOBSON
ON BEHALF OF COMMISSION STAFF
SEPTEMBER 1999

Q. What is your name and by whom are you employed?

A. My name is David A. Jacobson and I am presently employed as a Utility Analyst with the Fixed Utilities Division of the Public Utilities Commission. My business address is Public Utilities Commission, State Capitol Building, Pierre, South Dakota 57501.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science Degree in Business Administration majoring in management in 1980 and subsequently completed major course work in accounting at the University of South Dakota. I have been with the Public Utilities Commission since May of 1984.

Q. Have you previously testified before the Commission?

A. I have presented testimony in 13 rate increase applications and in various other docketed matters before the Commission.

Q. Were you assigned to work on this docket?

A. Yes.

Q. What is the purpose of your testimony in this proceeding?

A. I shall present Staff's determination of NorthWestern Public Service's (NWPS or Company) cash working capital allowance, gas storage rate base amount and NWPS's proposed tariff sheets.

Working Capital

Q. Has NWPS made a claim for working capital?

A. No, the Company made no claim for working capital.

Q. How were you able to perform a calculation for working capital?

A. In Data Request 1-3, I submitted to the Company the calculation of Working capital from the last NWPS natural gas rate case and requested that calculation be updated. That calculation was based on a lead lag study. A lead lag study is a study of time between (1) when a service is provided to a customer and when the utility receives revenue from that customer for that service; and (2) the time between when a service is provided to the utility and when the utility pays for that service. The difference between these is expressed in days. This difference multiplied by the average daily operating expense results in the working capital required for those operating expenses. Taxes collected by the Company and held until payment are also included in the working capital calculation. The detail for this can be found on Exhibit__(DAJ-1), Schedules 1 and 2.

Q. Why have you reflected federal income taxes currently payable as having no effect on working capital?

A. Adjusted test year federal income taxes currently payable are a negative amount. Negative federal income taxes do not create a working capital requirement.

Q. What is the effect of your working capital calculation?

A. Cash working capital requirements are negative $609,583 and collections available are $56,204 which are reductions to NWPS's rate base.

Gas Storage

Q. How has NWPS calculated their rate base allowance for gas storage?

A. The Company has calculated test year gas storage by averaging the test year beginning and the twelve month end balances in the gas storage account. This method is commonly known as the thirteen month average method.

Q. Is there anything wrong with the thirteen month average method?

A. When monthly average amounts are relatively stable throughout the year, the thirteen month average method is acceptable. The use of the thirteen month average method results in one month having both the beginning and ending balance counted. A problem arises when an account fluctuates widely because of seasonality. In the case of gas storage, balances during the month of December, which is the month counted twice, are near their peak.

Q. How should this be corrected?

A. Accounts which have balances varying widely depending on seasonal fluctuations should be calculated using a twelve month average. In this case, I have recalculated the storage gas balance using an average of the twelve monthly averages which can be seen on Exhibit__(DAJ-2), Schedule 1. The result is an adjustment lowering rate base by $37,790.

Tariff Sheets

Q. Have you reviewed the proposed tariff sheets submitted by NWPS in this case?

A. Yes. The tariff sheets submitted are acceptable with the condition that sheet numbers, effective dates and final rates be updated upon final rate determination.

Q. I have no further questions.

NORTHWESTERN PUBLIC SERVICE
South Dakota - Gas
Cash Working Capital
Test Year Ended 12-31-98

	Item (a)	As Filed (b)	Staff Adjustments (c)	Pro Forma Expense (d)	Expense Per Day (e)	Expense Lead Days (f)	Expense Dollar Days (g)
	Operation and Maintenance						
1	Cost of Gas	$21,484,514	$12,882	$21,497,396	$58,897	35.3	$2,079,064
2	Labor	3,166,227	(88,342)	3,077,885	8,433	7.6	64,091
3	Other O & M	3,888,377	(529,072)	3,359,305	9,204	38.1	350,672
4	Total O & M	$28,539,118	($604,532)	$27,934,586	$76,534		$2,493,827
	Taxes Other Than Income						
5	Ad valorem - South Dakota	909,733	0	909,733	2492	394.5	983,094
6	Deleware Franchise	12,547	0	12,547	34	45.6	1,550
7	Federal Highway Use	714	0	714	2	63.0	126
8	Workers Comp - Self Insured	377	0	377	1	7.6	8
9	South Dakota - Gross Revenue	53,648	938	53,648	147	333.5	49,025
10	Employer FICA	195,221	0	195,221	535	22.1	11,824
11	Unemployment Tax - Federal	3,821	0	3,821	10	76.0	760
12	Total Taxes Other	$1,176,061	$938	$1,176,061	$3,221		$1,046,387
13	Depreciation	1,616,790	0	1,616,790	4,430	0.0	0
14	Deferred Federal Income Tax	1,362,655	0	1,362,655	3,733	0.0	0
15	Federal Income Taxes	(861,612)	21,840	(839,772)	0	37.0	0
16	Preferred Stock Dividends		13,137	13,137	36	45.6	1,642
17	Long Term Debt Interest		1,608,427	1,608,427	4,407	91.3	402,359
18	Total	$31,833,012	$1,039,810	$32,871,884	$92,361	42.7	$3,944,215
19	Revenue Lag Days	36.1					
20	Expense Lead Days	42.7					
21	Net Lag Days	(6.6)					
22	Expense Per Day	$92,361					
23	Working Capital	($609,583)					

Sources:

Column (b) line 1 & 13: Exhibit__(RGT-1), Schedule 3, page 1
line 2: NWPS Exhibit__(TPH-1), page 27
line 3: O&M + Manufactured gas plant + rate case expense - labor and cost of gas
lines 5-9: NWPS Exhibit__(TPH-1), page 44
lines 10-11: Fax from Virg Garbers 9/16/99
line 14: Statement K, page 7 of 7
line 15: Jacobson workpaper

Column (c) lines 1-3: Exhibit__(RGT-1), Schedule 3, page 2
line9: Exhibit__(RGT-1), Schedule 3, page 2 (335+603=938) (402,290 x .0015 = 603)
line 15: Jacobson workpaper
line 16: Weighted cost of preferred x rate base
line 17: Weighted cost of LTD x rate base

Column (f) lines 1-3, 5-7, 10-11& 16-17: NWPS Data Response 1-3
line 8: Same as labor
line 9: Staff workpaper reflecting June 1st payment date per SDCL 49-1A-3
line 15: Staff workpaper

NORTHWESTERN PUBLIC SERVICE
South Dakota - Gas
Tax Collections Available
Test Year Ended 12-31-98

Exhibit__(DAJ-1)
Schedule 2
Page 1 of 1

	Item	As Filed	Staff Adjustments	As Adjusted	Average Daily Collections	Average Days Available	Working Cash Available
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Employee FICA	$195,221	$0	$195,221	$535	8	$4,280
2	Federal Witholding	647,350	0	647,350	1,774	8	14,192
3	South Dakota Sales Tax	1,601,067	19,164	1,620,231	4,439	8.5	37,732
4	Total Tax Collections Available						$56,204

Sources:

Column (b) lines 1 & 2: NWPS Data Response faxed from Virg Garbers 9/15/99 and 9/21/99
line 3: 4.757% effective tax rate* applied to NWPS's normalized revenue ($33,657,074)

Column (c) line 3: 4.757% effective tax rate* applied to Staff revenue adjustments

Column (f) lines 1 & 2: NWPS Data Response 1-3
line 3: [(365/12)/2] + 30.4 - 36.13 (revenue lag) reflects South Dakota sales tax remmittance statute

*4.757% = test year sales tax per books ($1,417,929) divided by test year revenue per books ($29,804,685)

Exhibit__(DAJ-2)
Schedule 1

NORTHWESTERN PUBLIC SERVICE
South Dakota - Gas
Gas Storage Adjustment
Test Year Ended 12-31-98

	(a)	Month-End Balance (b)	Monthly Average (c)
1	December, 1997	$1,127,205	
2	January, 1998	803,607	$965,406
3	February	501,523	652,565
4	March	261,058	381,291
5	April	93,962	177,510
6	May	0	46,981
7	June	278,022	139,011
8	July	592,938	435,480
9	August	788,262	690,600
10	September	1,015,976	902,119
11	October	1,252,202	1,134,089
12	November	1,231,570	1,241,886
13	December, 1998	1,184,485	1,208,028
14	Average	$702,370	$664,581
15	As filed		702,370
16	Rate base adjustment		($37,790)

Sources: NWPS Exhibit (TPH-1), page 55

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Northwestern Public Service
Application for Authority to Increase
Natural Gas Rates in South Dakota

Docket No. NG99-002

Testimony of Martin C. Bettmann
On Behalf of the Commission Staff
September, 1999

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Q. What is your name and by whom are you employed?

A. My name is Martin C. Bettmann and I am employed as a Staff Engineer by the South Dakota Public Utilities Commission (Commission). My business address is South Dakota Public Utilities Commission, 500 East Capitol Avenue, Pierre, South Dakota, 57501-5070.

Q. Please describe your professional and educational background.

A. I received my Bachelor of Science degree in Engineering from South Dakota State University in 1975. After graduation I was employed by an engineering consulting firm in Aberdeen, South Dakota, prior to taking my present position as a Staff Engineer with the Commission in November, 1977.

Q. Please describe what your job involves.

A. My primary responsibilities with the Commission Staff (Staff) include managing the pipeline safety inspection program, the review of energy conversion and transmission facility siting applications and evaluating and making recommendations on electric and natural gas rates and tariffs. I also advise the Staff on the various engineering and technical matters that come before the Commission.

Q. Have you testified before the Commission in any previous electric or natural gas rate case proceedings?

A. Yes. I have submitted written testimony in four electric rate cases and three natural gas rate cases.

In previous rate cases, my written testimony has addressed fuel oil usage at combustion turbine and internal combustion electric generating plants, steam production plant depreciation proposals, the apportionment of revenue responsibility among the customer classes and the rate design proposals, and the level of gas sales to a power plant and the purchased gas cost reflected in that companies Operations & Maintenance expense.

Q. Are you familiar with Northwestern Public Service's (NPS) application for an increase in revenues?

A. Yes. I have reviewed the direct testimony of the NPS witnesses, their exhibits and the responses to Staff data requests pertinent to the preparation of my testimony.

Q. What is your role in this docket?

A. For this filing, I am responsible for the review and analysis of NPS's proposed pro forma new load adjustments. I have also reviewed the weather normalization adjustment sponsored by NPS witness Jeffrey J. Decker. My testimony also summarizes Staff's proposed rate design.

Q. In your opinion, are there any changes necessary to NPS's proposed pro forma new load adjustments?

A. It is my opinion that the pro forma new load adjustment of 7,200,000 Therms shown in Column (c), Line 19, of NPS Exhibit___(TPH-1), Page 15 of 58, should be reduced by 450,000 Therms to 6,750,000 Therms. The new load adjustment as proposed by NPS includes projected natural gas deliveries to a new South Dakota Wheat Growers facility located in Mellette. The facilities that will be used to serve the facility were constructed during Calendar Year 1999 and are not included in the 1998 Test Year rate base. Therefore, it is my opinion that the pro

forma new load adjustment of 450,000 Therms, apportioned to that facility, should not be included in the Gas Revenue Requirement calculation.

Q. In your opinion, what changes should be made to NPS's proposed weather normalization adjustment?

A. It is my opinion that the weather normalization adjustments, as proposed by NPS witness Decker, are acceptable.

Q. How are the revenue increase calculations you performed in Exhibit ____ (MCB-2) different from NPS's calculations as found in NPS Exhibit___(TPH-1)?

A. The obvious difference between the two methods is in the way they are depicted on the spreadsheets. The other difference is the incorporation of Staff's proposed change to the pro forma new load adjustment for Rate 87 (Option B) sales growth, and the difference in revenue deficiencies by class.

Q. What rate design changes does NPS propose for Residential - Rate Code 81 customers?

A. NPS is proposing to keep the two step declining block rate structure that is presently in place. The most significant proposed rate change for this customer class is an increase in the Customer Charge from $4.50 to $6.00. Staff witness Robert G. Towers has submitted testimony indicating that the proposed $6.00 charge is cost justified and, consequently, I have incorporated it into my recommended rate structure. Additionally, I note that even with this substantial increase, NPS' residential customer charge would remain the lowest of the major gas companies in the state. Both Montana-Dakota Utilities and MidAmerican Energy have residential gas service customer charges of $6.50 per month.

Mr. Towers has calculated a revenue deficiency of $246,189 for this customer class. Because the increase in the customer charge produces more revenue than $246,189 it is necessary to reduce the Non-Gas Commodity Charges for the class. I would make these reductions in the first usage block by reducing that rate from $0.2000 per therm to $0.1623 per therm and retaining the second block rate

of $0.1220 per therm. Taking the reduction in the first block reduces somewhat the impact of the higher customer charge on low volume customers.

Q. What rate changes has NPS proposed for the Small Commercial - Rate Code 82 customer class?

A. NPS is proposing to keep the current three step declining block rate structure. As proposed, the monthly Customer Charge per Meter would be raised from $4.50 to $7.00. As for the residential class, Staff witness Towers has testified that the $7.00 charge is cost justified and, for this reason, I have adopted it.

The revenue deficiency for this class determined by Mr. Towers is $134,587 which is less than the revenue generated by the $7.00 customer charge. Consequently, I would again reduce the initial block Non-Gas Commodity Charge, reducing it from $0.1141 per therm to $0.1126 per therm, leaving the second and third blocks unchanged.

Q. What changes are proposed for the Large Commercial/Industrial Firm - Rate Code 84 customers?

A. NPS's proposed changes would increase the Customer Charge from $70.00 to $80.00 for the Option A customers, and from $260.00 to $280.00 for the Option B customers. Because Staff witness Towers has found the proposed customer charges to be cost-justified, I have incorporated them into my recommended rates.

I have concluded that the Non-Gas Commodity Charge for the Option A customers would be decreased to $0.0347 per therm and decreased to $0.0163 for Option B customers.

Q. What changes are proposed for the Interruptible - Rate Code 85 customers?

A. NPS is proposing the same increase in the Customer Charge for the Rate Code 85 customers as it did for the Rate 84 customers. I have concluded that the Non-Gas Commodity Charge for the Option A customers would be decreased to

$0.0347 per therm and to $0.0163 for Option B customers for these customers, also.

Q. What changes are proposed for the Transportation - Rate Code 87 customers?

A. NPS is proposing to increase the Customer Charge from $70.00 to $130.00 for the Option A customers, and from $260.00 to $330.00 for the Option B customers. The Customer Charge for customers receiving service under a Contract with Deviations would also be increased from $260.00 to $330.00. Based on Mr. Towers' testimony I have incorporated these charges into my proposed rates.

Once again, I have concluded that the Non-Gas Commodity Charge for the Option A customers would be decreased to $0.0347 per therm and to $0.0163 for Option B customers for these customers, the same as it was for the Rate 84 and 85 customers. Mr. Towers has calculated a revenue deficiency of $21,514 for the customer class that includes the Rate Code 84, 85, and 87 customers.

Q. Have you prepared a bill comparison using the current rates and Staff's proposed rate design?

A. Yes, I have. In Exhibit ____ (MCB-3) I compare typical bills using the current rates with Staff's proposed rates for Rate Code 81, 82, and 84 customers. For the Rate Code 85 and 87 customers I did not calculate typical bills, but Exhibit ____ (MCB-4) does show the overall percent increase for the customers receiving service under these two rate codes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Northwestern Public Service
South Dakota - Gas
Revenue Increase
Per Staff

Line No.	RATE STEP	THERMS (A)	THERMS (B)	TOTAL MARGIN (C) Test Year Revenue	REVISED (D) Proposed Revenue	INCREASE (F) Revenue (Inc./Dec.)	PERCENT INCREASE (G) Percent (Inc./Dec.)
	REVENUE INCREASE by RATE CODE						
1	RATE 81	33,197,790	33,197,790	20,189,402	20,435,748	**246,346**	1.2%
2	RATE 82	15,866,880	15,866,880	8,226,248	8,360,735	**134,487**	1.6%
3	RATE 84 (OPTION A&B)	5,936,020	5,936,020	2,235,630	2,245,649	10,019	0.4%
4	RATE 85 (OPTION A&B)	4,425,500	4,425,500	1,431,062	1,437,789	6,727	0.5%
5	RATE 87 (OPTION A&B)	29,121,130	29,121,130	1,211,082	1,215,384	4,302	0.4%
6	COMBINED RATE 84, 85, and 87 Sum of Line 3, 4, and 5	39,482,650	39,482,650	4,877,775	4,898,822	**21,047**	0.4%
7	TOTAL (Sum of Lines 1, 2, and 6)	88,547,320	88,547,320	$ 33,293,425	$ 33,695,306	$ **401,881**	1.2%

Northwestern Public Service
South Dakota - Gas
Residential - Rate 81 and Small Commercial - Rate 82
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Residential - Rate Code 81**									
2										
3		ALL THERMS CURRENTLY (FIRST 30)	Therms	9,414,430	9,414,430	0.2000	0.1623	1,882,886	1,527,962	(354,924)
4		EXCESS	Therms	23,783,360	23,783,360	0.1220	0.1220	2,901,570	2,901,570	0
5										
6		CUSTOMER CHARGE	BILL	400,847	400,847	4.50	6.00	1,803,812	2,405,082	601,271
7										
8		AD VALOREM TAX ADJUSTMENT		33,197,790	33,197,790	0.0156	0.0156	517,886	517,886	0
9		MGP REMOVAL COST ADJUSTMENT		33,197,790	33,197,790	0.0140	0.0140	464,769	464,769	0
10		GAS COST COMMODITY CHARGE		33,197,790	33,197,790	0.2043	0.2043	6,782,308	6,782,308	0
11		GAS COST DEMAND CHARGE		33,197,790	33,197,790	0.1758	0.1758	5,836,171	5,836,171	0
12										
13		TOTAL		33,197,790	33,197,790			20,189,402	20,435,748	246,346
14	**Small Commercial - Rate Code 82**									
15										
16		ALL THERMS CURRENTLY (FIRST 400)	Therms	8,490,570	8,490,570	0.1141	0.1126	968,774	956,038	(12,736)
17		NEXT 1,600	Therms	6,106,520	6,106,520	0.0841	0.0841	513,558	513,558	0
18		EXCESS	Therms	1,269,790	1,269,790	0.0541	0.0541	68,696	68,696	0
19										
20		CUSTOMER CHARGE	BILL	58,889	58,889	4.50	7.00	265,001	412,223	147,223
21										
22		AD VALOREM TAX ADJUSTMENT		15,866,880	15,866,880	0.0099	0.0099	157,082	157,082	0
23		MGP REMOVAL COST ADJUSTMENT		15,866,880	15,866,880	0.0140	0.0140	222,136	222,136	0
24		GAS COST COMMODITY CHARGE		15,866,880	15,866,880	0.2043	0.2043	3,241,604	3,241,604	0
25		GAS COST DEMAND CHARGE		15,866,880	15,866,880	0.1758	0.1758	2,789,398	2,789,398	0
26										
27		TOTAL		15,866,880	15,866,880			8,228,248	8,360,735	134,487

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Firm - Rate 84 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial Firm - Rate									
1	**Code 84 (Option A)**									
2										
3		ALL THERMS	Therms	5,505,570	5,505,570	0.0364	0.0347	200,403	191,043	(9,359)
4										
5		CUSTOMER CHARGE	BILL	1,963	1,963	70.00	80.00	137,410	157,040	19,630
6										
7		AD VALOREM TAX ADJUSTMENT		5,505,570	5,505,570	0.0064	0.0064	35,236	35,236	0
8		MGP REMOVAL COST ADJUSTMENT		5,505,570	5,505,570	0.0140	0.0140	77,078	77,078	0
9		GAS COST COMMODITY CHARGE		5,505,570	5,505,570	0.2300	0.2300	1,266,281	1,266,281	0
10		GAS COST DEMAND CHARGE		425,480	425,480	0.8700	0.8700	370,168	370,168	0
11		RELEASE CAPACITY/BALANCING SURCHARGE		680,040	680,040	0.0170	0.0170	11,561	11,561	0
12		SUBTOTAL		5,505,570	5,505,570			2,098,136	2,108,408	10,271
	Large Commercial/Industrial Firm - Rate									
13	**Code 84 (Option B)**									
14										
15		ALL THERMS	Therms	430,450	430,450	0.0180	0.0163	7,748	7,016	(732)
16										
17		CUSTOMER CHARGE	BILL	24	24	260.00	280.00	6,240	6,720	480
18										
19		AD VALOREM TAX ADJUSTMENT		430,450	430,450	0.0042	0.0042	1,808	1,808	0
20		MGP REMOVAL COST ADJUSTMENT		430,450	430,450	0.0140	0.0140	6,026	6,026	0
21		GAS COST COMMODITY CHARGE		430,450	430,450	0.2300	0.2300	99,004	99,004	0
22		GAS COST DEMAND CHARGE		18,120	18,120	0.8700	0.8700	15,764	15,764	0
23		RELEASE CAPACITY/BALANCING SURCHARGE		53,180	53,180	0.0170	0.0170	904	904	0
		SUBTOTAL		430,450	430,450			137,494	137,242	(252)
24										
25		TOTAL		5,936,020	5,936,020			$2,235,630	$2,245,649	$10,019

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial									
1	**Interruptible - Rate Code 85 (Option A)**									
2										
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0347	143,333	136,639	(6,694)
4										
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290
6										
7		AD VALOREM TAX ADJUSTMENT		3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0
8		MGP REMOVAL COST ADJUSTMENT		3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0
9		GAS COST COMMODITY CHARGE		3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0
10		RELEASE CAPACITY/BALANCING SURCHARGE		3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,287,042	6,596
	Large Commercial/Industrial									
12	**Interruptible - Rate Code 85 (Option B)**									
13										
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0163	8,780	7,951	(829)
15										
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960
17										
18		AD VALOREM TAX ADJUSTMENT		487,770	487,770	0.0042	0.0042	2,049	2,049	0
19		MGP REMOVAL COST ADJUSTMENT		487,770	487,770	0.0140	0.0140	6,829	6,829	0
20		GAS COST COMMODITY CHARGE		487,770	487,770	0.2300	0.2300	112,187	112,187	0
21		RELEASE CAPACITY/BALANCING SURCHARGE		487,770	487,770	0.0170	0.0170	8,292	8,292	0
22		SUBTOTAL		487,770	487,770			150,616	150,747	131
23										
24		TOTAL		4,425,500	4,425,500			1,431,062	1,437,789	6,727

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Transportation - Rate Code 87 (Option A)**									
2										
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0347	48,393	46,133	(2,260)
4										
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720
6										
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0
10	SUBTOTAL			1,329,490	1,329,490			97,355	113,815	16,460
11	**Transportation - Rate Code 87 (Option B)**									
12										
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0163	500,250	453,004	(47,246)
14										
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320
16										
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0
20	SUBTOTAL			27,791,640	27,791,640			1,113,727	1,101,570	(12,158)
21										
22	TOTAL			29,121,130	29,121,130			1,211,082	1,215,384	4,302

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$4.50	$6.00
2	FIRST 30 THERMS	$0.20000	$0.16230
3	EXCESS THERMS	$0.12200	$0.12200
4	PGA and OTHER ADJ.	$0.40970	$0.40970

Residential - Rate Code 81

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$4.50	$6.00	$1.50	33.33%
6	10	10.60	11.72	1.12	10.60%
7	25	19.74	20.30	0.56	2.82%
8	50	33.43	33.79	0.37	1.10%
9	75	46.72	47.09	0.37	0.79%
10	80	49.38	49.75	0.37	0.75%
11	100	60.01	60.38	0.37	0.61%
12	125	73.30	73.67	0.37	0.50%
13	150	86.60	86.96	0.37	0.43%
14	175	99.89	100.26	0.37	0.37%
15	200	113.18	113.55	0.37	0.33%
16	225	126.47	126.84	0.37	0.29%
17	250	139.77	140.13	0.37	0.26%
18	300	166.35	166.72	0.37	0.22%
19	400	219.52	219.89	0.37	0.17%
20	500	272.69	273.06	0.37	0.14%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	196	$110.80	$111.17	$0.37	0.3%
FEB	166	$95.22	$95.59	$0.37	0.4%
MAR	148	$85.71	$86.08	$0.37	0.4%
APR	126	$73.80	$74.17	$0.37	0.5%
MAY	49	$32.65	$33.02	$0.37	1.1%
JUN	23	$18.81	$19.42	$0.62	3.3%
JUL	18	$15.77	$16.57	$0.80	5.1%
AUG	15	$13.58	$14.52	$0.94	6.9%
SEP	14	$13.27	$14.23	$0.96	7.2%
OCT	32	$23.76	$24.13	$0.37	1.6%
NOV	82	$50.27	$50.64	$0.37	0.7%
DEC	118	$69.77	$70.14	$0.37	0.5%
TOTAL	988	$603.41	$609.68	$6.27	1.0%

AVERAGE MONTHLY USE = 82 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$4.50	$7.00
22	FIRST 400 THERMS	$0.11410	$0.11260
23	NEXT 1,600 THERMS	$0.08410	$0.08410
24	EXCESS THERMS	$0.05410	$0.05410
25	PGA and OTHER ADJ.	$0.40970	$0.40970

SMALL COMMERCIAL - Rate Code 82

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
26	0	4.50	7.00	$2.50	55.56%
27	50	30.69	33.12	2.42	7.90%
28	100	56.88	59.23	2.35	4.13%
29	200	109.26	111.46	2.20	2.01%
30	350	187.83	189.81	1.97	1.05%
31	500	263.40	265.30	1.90	0.72%
32	750	386.85	388.75	1.90	0.49%
33	1000	510.30	512.20	1.90	0.37%
34	1500	757.20	759.10	1.90	0.25%
35	2000	1,004.10	1,006.00	1.90	0.19%
36	2500	1,236.00	1,237.90	1.90	0.15%
37	3,000	1,467.90	1,469.80	1.90	0.13%
38					
39					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	621	316.57	318.47	1.90	0.6%
FEB	577	296.21	298.11	1.90	0.6%
MAR	503	261.61	263.51	1.90	0.7%
APR	397	212.54	214.44	1.90	0.9%
MAY	138	76.60	78.90	2.29	3.0%
JUN	68	40.28	42.68	2.40	6.0%
JUL	60	35.92	38.33	2.41	6.7%
AUG	54	32.83	35.25	2.42	7.4%
SEP	50	30.92	33.35	2.42	7.8%
OCT	90	51.90	54.27	2.36	4.6%
NOV	261	141.25	143.35	2.11	1.5%
DEC	394	210.73	212.64	1.91	0.9%
TOTAL	3,214	$1,707	$1,733	$25.93	1.5%

AVERAGE MONTHLY USE = 268 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
38	CUSTOMER CHARGE	$70.00	$80.00
39	ALL THERMS	$0.03640	$0.03470
40	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION A)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
41	0	70.00	80.00	$10.00	14.29%
42	250	141.70	151.28	9.58	6.76%
43	500	213.40	222.55	9.15	4.29%
44	750	285.10	293.83	8.73	3.06%
45	1,000	356.80	365.10	8.30	2.33%
46	1,500	500.20	507.65	7.45	1.49%
47	2,000	643.60	650.20	6.60	1.03%
48	3,000	930.40	935.30	4.90	0.53%
49	4,000	1,217.20	1,220.40	3.20	0.26%
50	5,000	1,504.00	1,505.50	1.50	0.10%
51	6,000	1,790.80	1,790.60	(0.20)	-0.01%
52	7,000	2,077.60	2,075.70	(1.90)	-0.09%
53	8,000	2,364.40	2,360.80	(3.60)	-0.15%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	6,298	1,876.18	1,875.47	(0.71)	0.0%
FEB	5,230	1,569.94	1,571.04	1.11	0.1%
MAR	4,715	1,422.15	1,424.13	1.99	0.1%
APR	4,008	1,219.43	1,222.61	3.19	0.3%
MAY	2,138	683.28	689.64	6.36	0.9%
JUN	392	182.53	191.87	9.33	5.1%
JUL	1,376	464.76	472.42	7.66	1.6%
AUG	737	281.46	290.21	8.75	3.1%
SEP	658	258.59	267.47	8.88	3.4%
OCT	1,287	439.09	446.90	7.81	1.8%
NOV	2,808	875.33	880.56	5.23	0.6%
DEC	3,471	1,065.37	1,069.47	4.10	0.4%
TOTAL	33,118	$10,338	$10,402	$63.70	0.6%

54

AVERAGE MONTHLY USE = 2,760 Therms

LINE NO.		PRESENT	PROPOSED
55	CUSTOMER CHARGE	$260.00	$280.00
56	ALL THERMS	$0.01800	$0.01630
57	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION B)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
58	0	260.00	280.00	$20.00	7.69%
59	250	327.10	346.68	19.58	5.98%
60	500	394.20	413.35	19.15	4.86%
61	1,000	528.40	546.70	18.30	3.46%
62	2,300	931.00	946.75	15.75	1.69%
63	5,000	1,602.00	1,613.50	11.50	0.72%
64	10,000	2,944.00	2,947.00	3.00	0.10%
65	20,000	5,628.00	5,614.00	(14.00)	-0.25%
66	35,000	9,654.00	9,614.50	(39.50)	-0.41%
67	50,000	13,680.00	13,615.00	(65.00)	-0.48%
68	60,000	16,364.00	16,282.00	(82.00)	-0.50%
69	70,000	19,048.00	18,949.00	(99.00)	-0.52%
70	75,000	20,390.00	20,282.50	(107.50)	-0.53%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	70,034	19,065.09	18,965.98	(99.11)	-0.5%
FEB	32,177	8,896.28	8,861.58	(34.70)	-0.4%
MAR	28,048	7,787.98	7,760.30	(27.68)	-0.4%
APR	19,295	5,438.85	5,426.05	(12.80)	-0.2%
MAY	12,867	3,713.40	3,711.53	(1.87)	-0.1%
JUN	5,147	1,641.43	1,652.68	11.25	0.7%
JUL	1,253	596.44	614.31	17.87	3.0%
AUG	377	361.19	380.55	19.36	5.4%
SEP	811	477.67	496.29	18.62	3.9%
OCT	3,412	1,175.79	1,189.99	14.20	1.2%
NOV	10,386	3,047.62	3,049.97	2.34	0.1%
DEC	31,388	8,684.51	8,651.15	(33.36)	-0.4%
TOTAL	215,224	$60,886	$60,760	($125.68)	-0.2%

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AVERAGE MONTHLY USE = 17,935 Therms

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
	Large Commercial/Industrial										
1	**Interruptible - Rate Code 85 (Option A)**										
2											
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0347	143,333	136,639	(6,694)	
4											
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290	
6											
7	AD VALOREM TAX ADJUSTMENT			3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0	
8	MGP REMOVAL COST ADJUSTMENT			3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0	
9	GAS COST COMMODITY CHARGE			3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0	
10	RELEASE CAPACITY/BALANCING SURCHARGE			3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0	
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,287,042	6,596	0.5%
	Large Commercial/Industrial										
12	**Interruptible - Rate Code 85 (Option B)**										
13											
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0163	8,780	7,951	(829)	
15											
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960	
17											
18	AD VALOREM TAX ADJUSTMENT			487,770	487,770	0.0042	0.0042	2,049	2,049	0	
19	MGP REMOVAL COST ADJUSTMENT			487,770	487,770	0.0140	0.0140	6,829	6,829	0	
20	GAS COST COMMODITY CHARGE			487,770	487,770	0.2300	0.2300	112,187	112,187	0	
21	RELEASE CAPACITY/BALANCING SURCHARGE			487,770	487,770	0.0170	0.0170	8,292	8,292	0	
22		SUBTOTAL		487,770	487,770			150,616	150,747	131	0.1%
23											
24		TOTAL		4,425,500	4,425,500			1,431,062	1,437,789	6,727	0.5%

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	**Transportation - Rate Code 87 (Option A)**										
2											
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0347	48,393	46,133	(2,260)	
4											
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720	
6											
7		EXTENDED SERVICE RIDER DISCOUNT						0	0	0	
8		AD VALOREM TAX ADJUSTMENT		1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0	
9		MGP REMOVAL COST ADJUSTMENT		1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0	
10		SUBTOTAL		1,329,490	1,329,490			97,355	113,815	16,460	16.9%
11	**Transportation - Rate Code 87 (Option B)**										
12											
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0163	500,250	453,004	(47,246)	
14											
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320	
16											
17		EXTENDED SERVICE RIDER DISCOUNT						(42,090)	(47,322)	(5,232)	
18		GAS COST COMMODITY CHARGE		27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0	
19		RELEASE CAPACITY/BALANCING SURCHARGE		27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0	
20		SUBTOTAL		27,791,640	27,791,640			1,113,727	1,101,570	(12,158)	-1.1%
21											
22		TOTAL		29,121,130	29,121,130			1,211,082	1,215,384	4,302	0.4%

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

NORTHWESTERN PUBLIC SERVICE
DOCKET NO. NG99-002

TESTIMONY AND EXHIBITS OF MICHELE M. FARRIS
ON BEHALF OF THE COMMISSION STAFF
SEPTEMBER 1999

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Northwestern Public Service
Docket No. NG99-002

Testimony of Michele M. Farris
On Behalf of Commission Staff

September 1999

Q. Please state your name, business address and current position.

A. My name is Michele M. Farris and my business address is: Public Utilities Commission, 500 East Capitol, Pierre, SD 57501. I am presently employed as a Utility Analyst.

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from South Dakota State University in May 1987. I received a Master of Science degree in Civil Engineering from the University of Colorado in May 1994. I am a Registered Professional Engineer in the State of South Dakota. I commenced employment with the Public Utilities Commission in January 1999.

Q. Have you previously presented testimony before the Commission?

A. Yes. I have submitted written testimony in MidAmerican Energy Company's rate increase application, Docket No. NG98-011. In addition, I presented testimony in the sale of stock for Union Telephone Company of Hartford and Armour Independent Telephone Co., including its wholly-owned subsidiary, Bridgewater-Canistota Independent Telephone Co. to MJD Services Corp., Docket No. TC99-005.

Q. What is the purpose of your testimony in this proceeding?

A. I shall express my opinion regarding adjustments to Northwestern Public Service's charitable contribution expenses, economic development expenses, industry and association dues, chamber dues, advertising expenses, and labor expenses, including incentive compensation expenses.

Q. Did Northwestern Public Service include charitable contribution expenses in its claimed cost of service?

A. No. Northwestern Public Service has charged charitable contributions as a below the line item for rate making purposes. No charitable contribution amounts were included in South Dakota test year expenditures.

Q. What is your opinion in regard to Northwestern Public Service's claimed association dues?

A. It is my opinion that Northwestern Public Service's proposed cost of service includes association dues that are either unrelated to its South Dakota retail gas business or are unnecessary for the provision of safe, adequate and reliable natural gas service. I recommend that account 930.2 Miscellaneous General Expenses be reduced by $20,771. My adjustment is shown on Exhibit__(MMF-1), Schedule 1, line 35.

Q. Why is it your opinion that these association dues be excluded?

A. Northwestern Public Service's memberships to SD Chamber of Commerce Associations and Electric Associations are not necessary for the provision of safe, adequate and reliable natural gas service. Moreover, the dues paid to economic development associations are not considered association expenses and should not be charged as industry and association dues.

Q. What is your opinion regarding institutional/promotional/goodwill advertising expenses?

A. Northwestern Public Service has eliminated, for rate making purposes, its test year institutional/promotional/goodwill advertising costs in accounts 913 and 930.2 . The advertising expenses charged to account 909 are for gas safety advertisements. I recommend that all of Northwestern Public Service's gas safety advertisements be allowed in rates.

Q. Should Northwestern Public Service's economic development expenses be included in rates?

A. No. I recommend that $6,565 associated with test year economic development expenses be removed from Northwestern Public Service's claimed cost of service. My adjustment is shown on Exhibit__(MMF-1),

Schedule 1, line 36.

In order to recover economic development expenses in rates, Northwestern Public Service should be required to develop an economic development program that is approved annually by the Commission. In the past, the Commission has approved economic development plans for other investor owned utilities providing natural gas service in South Dakota. Typically these plans include cost sharing between the ratepayer and the shareholder. However, Northwestern Public Service does not have an approved economic development plan on file with the Commission. Therefore, these economic development expenses should not be allowed in rates.

Q. What is your opinion in regard to Northwestern Public Service's claimed labor costs?

A. It is my opinion after reviewing Northwestern Public Service's submitted material that no changes be made to Northwestern Public Service's claimed pro forma labor costs. Northwestern Public Service reflected a 3 percent pro forma labor adjustment for union and non-union labor. The union contract in effect for calendar years 1997, 1998, and 1999 allows for an annual three percent increase to all union employees. The salary increase for non-union labor was 3.66% in 1998 and 4.35% in 1999. A three percent labor increase is reasonable.

Q. During your analysis did you also review Northwestern Public Service's test year incentive compensation plan?

A. Yes I did. Northwestern Public Service offers an incentive compensation plan for eligible employees. This plan is referred to as the NorthSTAR plan.

Q. What is the stated objective of the NorthSTAR plan?

A. In Northwestern Public Service's response to data request 2-20, the objective of the NorthSTAR plan was stated as follows:

> "The Northwestern NorthSTAR Plan is established to accomplish the following objectives: (1) to motivate and reward outstanding performance by Northwestern Corporation (the "Company") and its employees by providing additional compensation to eligible employees who influence the profitability of the Company; (2) to compare the Company's performance to established annual objectives; (3) to compare individual performance to established

annual objectives; (4) to focus on stockholder and ratepayer interests and (5) to support long-term objectives by achieving short-term goals."

Q. Who is eligible to participate in the NorthSTAR plan?

A. Eligible employees are those full-time employees who have completed one year of service with Northwestern Corporation and who have been selected for participation by Northwestern Corporation management. The plan was developed to compensate those eligible employees who influence the profitability of Northwestern Corporation.

Q. How is the incentive compensation award determined for the NorthSTAR plan?

A. The NorthSTAR plan has four major categories that are equally weighted to determine the compensation paid. They include i) company performance as measured by customer satisfaction; ii) company performance versus operating budget; iii) company performance versus annual objective (i.e. earnings per share); and iv) employee performance versus individual objectives. Goals are set annually for each of these categories. Performance versus operating budget measures the net income of the company as compared to the operating budget. Compensation is paid based on the amount the capital expenditures are under budget and the amount the operating income is over budget. The company performance versus annual objective measures earnings per share of the company. In test year 1998, each goal was weighted at 25% of the possible award. The company achieved 100% of the customer satisfaction and operating net income goals set for test year 1998. The company achieved 64.29% of the earnings per share goal set for test year 1998. The company was not able to provide the percent achieved for the individual goals for employees for test year 1998. Since Northwestern Public Service did not provide a breakdown of how much money was awarded for each goal, I assumed that each component goal of the NorthSTAR plan comprised 25% of the total amount awarded. As shown on Exhibit __(MMF-1), Schedule 2 each goal had the potential to be worth $53,772.

Q. What is your opinion regarding Northwestern Public Service's claimed incentive compensation?

A. It is my opinion that Northwestern Public Service's claimed cost of service be reduced by $88,342 (see Exhibit__(MMF-1), Schedule 2.)

Q. Why is it your opinion that this portion of the incentive compensation plan be excluded?

A. The compensation paid is dependant on how well the company achieves these goals. The company performance versus operating budget and company performance versus annual objective goals are based on objectives that should be established by any prudently managed utility. The stockholders, not ratepayers, are the direct beneficiaries when the company achieves its financial performance goals. Therefore, while the use of such goals is up to the company's discretion, it is my opinion that the benefit of such goals are directed to shareholders and therefore they should pay for this aspect of the plan.

Q. Does that conclude your testimony?

A. Yes it does.

Northwestern Public Service Company
South Dakota-Gas
Account 930.2 Miscellaneous General Expense
Test Year Ended December 31, 1998

Exhibit__(MMF-1)
Schedule 1
Page 1 of 1

	(a)		Company's Adjusted Amount (b)	Staff's Adjustment (c)
	Industry and Association Dues			
1	Midwest Energy Association		$ 1,130	-
2	Edison Electric Institute		$ 7,561	$ 7,561
3	South Dakota Electric		$ 2,424	$ 2,424
4	South Dakota Electric		$ 2,447	$ 2,447
5	North Central Electric Association		$ 401	$ 401
6	Institute of Gas Technology		$ 935	-
7	South Dakota Electric		$ 2,447	$ 2,447
8	Huron Area Chamber of Commerce		$ 561	$ 561
9	South Dakota Electric		$ 2,447	$ 2,447
10	South Dakota Chamber of Commerce		$ 561	$ 561
11	South Dakota Hall of Fame		$ 9	$ 9
12	American Society of Corporation		$ 79	-
13	Aberdeen Chamber of Commerce		$ 2	$ 2
14	Groton Chamber of Commerce		$ 14	$ 14
15	Webster Area Chamber of Commerce		$ 47	$ 47
16	Milbank Chamber of Commerce		$ 55	$ 55
17	Madison Area Chamber		$ 315	$ 315
18	Highmore Booster Club		$ 10	$ 10
19	Redfield Area Chamber		$ 68	$ 68
20	Greater Huron Development		$ 216	$ 216
21	Lake Preston Chamber		$ 10	$ 10
22	DeSmet Area Chamber		$ 10	$ 10
23	Mitchell Area Chamber		$ 270	$ 270
24	Parkston Commercial Club		$ 34	$ 34
25	Heartland News Inc.		$ 3	$ 3
26	Commercial Newspaper Service		$ 51	$ 51
27	Chamberlain Area Chamber		$ 102	$ 102
28	Yankton Manufacturers Association		$ 51	$ 51
29	Yankton Area Progressive		$ 168	$ 168
30	Yankton Area Chamber		$ 367	$ 367
31	Springfield Chamber of Commerce		$ 17	$ 17
32	Wagner Chamber of Commerce		$ 64	$ 64
33	Scotland Chamber of Commerce		$ 13	$ 13
34	Freeman Chamber of Commerce		$ 26	$ 26
35		Total	$ 22,915	$ (20,771)
36	Economic Development Expense		$ 6,565	$ (6,565)

Sources:
Lines 1 through 34: NWPS Data Response 5-03
Line 36: NWPS Data Response 5-04

Northwestern Public Service Company
South Dakota Gas
Incentive Compensation Adjustment
Test Year Ended December 31, 1998

Exhibit__(MMF-1)
Schedule 2
Page 1 of 1

	(a)	(b)
1	Incentive compensation test year expense - SD	$ 215,086
2	NorthSTAR plan component goals (4 @ 25%)	$ 53,772
	Adjustments to remove certain components	
3	Eliminate operating net income component (100% of 25%)	$ 53,772
4	Eliminate earnings per share component (64.29% of 25%)	$ 34,570
5	Adjustment to test year operating expense	$ (88,342)

Sources:

Line 1: NWPS Data Response 2-21
Line 2: NWPS Data Response 2-20
Lines 3 and 4: NWPS Data Response 6-06

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

NORTHWESTERN PUBLIC SERVICE
DOCKET NO. NG99-002

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
SEPTEMBER 1999

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

NORTHWESTERN PUBLIC SERVICE
DOCKET NO. NG99-002

TESTIMONY & EXHIBITS OF KEITH A. SENGER
ON BEHALF OF THE COMMISSION STAFF
SEPTEMBER 1999

Q. Please state your name and business address for the record.

A. Keith Senger, Public Utilities Commission, State Capitol Building, Pierre, South Dakota, 57501.

Q. By whom are you employed and in what position?

A. I am a utility analyst for the South Dakota Public Utilities Commission (SD PUC).

Q. Please describe your education and work experience.

A. I graduated from Northern State University in May of 1992 with a Bachelor's Degree in Business Administration with an emphasis in Accounting and minors in both Economics and Computer Management Information Systems. Since graduation, I have received over 300 hours of Continuing Professional Education (CPE) which has met or exceeded the requirements of the South Dakota Board of Accountancy, The American Institute of Certified Public Accountants (AICPA) and Generally Accepted Government Auditing Standards as issued by the Comptroller General of the United States.

In June of 1992, I started my employment with the State of South Dakota as an auditor for the Department of Legislative Audit (DLA). My employment at DLA consisted of performing the financial, compliance, performance and special project audits of various state agencies. In January of 1998, I accepted employment as the Audit and Compliance Manager for the South Dakota Department of Transportation (DOT). Duties included managing and directing the internal and external audit staff as well as federal

compliance staff. In January of 1999, I joined the South Dakota Public Utilities Commission as a staff utility analyst.

Q. Do you have any professional designations or memberships?

A. Yes, I do. I am a Certified Public Accountant (CPA) in accordance with the South Dakota Board of Accountancy and I am a member of the American Institute of Certified Public Accountants.

Q. Have you previously provided testimony before the South Dakota Public Utilities Commission?

A. Yes, I provided testimony on behalf of Commission Staff in Docket NG98-011.

Q. Are you familiar with Northwestern Public Service's (NWPS) application for an increase in natural gas rates in South Dakota, Docket NG99-002?

A. Yes. I have reviewed NWPS's pre-filed testimony, exhibits, working papers, and data responses supplied by NWPS at the request of Commission Staff as it pertains to the issues that I am addressing.

Q. What was your role in this docket?

A. I have performed a review of NWPS's per book amounts and the Company's pro forma adjustment for rate case expense and will provide testimony explaining Staff's position on these issues.

PER BOOK AMOUNTS

Q. As part of your job, did you perform a review at NWPS?

A. Yes. On September 8 and 9, 1999, PUC staff analyst Heather Forney and I met with NWPS staff at the Company office located in Huron, South Dakota. During our review we met with Rusty Molstad, Corporate Attorney; Virg Garbers, Assistant Controller; Ron Weich, Director of Property Accounting; Company Witnesses Tom Hitchcock, NEC Executive Vice President; and Jeff Decker, NEC Manager of Financial Services.

Q. During this site review, did you have an opportunity to review NWPS's accounting system?

A. Yes. Mr. Garbers gave us a general overview of the accounting system and the account coding structure.

Q. How many accounts does NWPS's accounting system utilize?

A. According to the chart of accounts, NWPS's accounting system has approximately 18,566 accounts. According to the 1998 year-end trial balance, NWPS used 5,927 accounts in the 1998 test period.

Q. After becoming generally familiar with NWPS's accounting system, did you focus on particular issues which involved this case?

A. Yes. Staff analyst Forney and I performed a limited review of the "per books" amounts provided by NWPS in the rate case. NWPS represents that the "per books" amounts are based on 1998 financial information, which was used as the test year for this case.

Q. Briefly describe what was done during the review.

A. 1) A judgmental sample of plant, revenue and expense amounts from Company Exhibit___(TPH-1), Schedule No.'s 2, 4.5, 4.6, 9, 9.1, 9.3 and 9.4 were traced to NWPS's 1998 year-end Trial Balance, 2) a sample of the Company accounting transaction lines was traced to supporting documentation, and 3) a sample of amounts from Company Exhibit___(TPH-1), Schedule No.'s 10 and 11 was traced to supporting documentation.

Q. What was the result of Staff's site review?

A. Based on procedures performed during our review, no variances were found and nothing came to our attention that caused staff to believe that the per-books amounts as filed in Docket NG99-002 are not presented in conformity with NWPS 1998 financial information.

RATE CASE EXPENSE

Q. **Have you reviewed the Company's adjustment for rate case expense?**

A. Yes. I have reviewed Company Witness Hitchcock's pre-filed testimony, exhibits and responses to Staff's data requests relating to rate case expense.

Q. What is your opinion with regard to rate case expense?

A. NWPS is proposing Company rate case expense of $50,000 and Commission expense of $100,000, totaling $150,000 recoverable through rates. The $100,000 the Company has included as Commission expense is the maximum amount, per SDCL 49-1A-8, that the Commission may assess for processing this docket. Based on costs incurred by Staff to process similar dockets, it is my opinion that this amount should be reduced to $70,000.

The Company justified the $50,000 of company expense as $10,000 in supplies, printing, postage, and travel, $20,000 for Return on Equity witness and $20,000 for Cost of Service / Allocation witness. Based on information gathered, it is my understanding that the Company no longer intends to hire a Cost of Service / Allocation witness, thus eliminating $20,000. Additionally, NWPS has prepared and filed their case without hiring a return on equity witness. If NWPS hires a return on equity witness, it will be for rebuttal purposes only. Because of the limited responsibility of this witness, I feel $10,000 is a reasonable amount. Therefore, I recommend a pro forma adjustment of $20,000 instead of the Company's $50,000. This $20,000 adjustment includes $10,000 for supplies, printing, postage, travel and miscellaneous expense plus $10,000 for a return on equity witness.

The Company proposes to amortize rate case expense over a three-year period. Based on the fact that the Company last filed for a gas rate increase in 1994, five years ago, I recommend that the amortization period should be increased to a five-year period.

The Company is also requesting a pro forma adjustment increasing rate base by the total rate case expense less one half of one year's amortization. I propose that the rate base adjustment should be the average balance of the unamortized portion of the rate case expense, or simply stated, one half of the rate case expense. Details for my adjustments can be found on Exhibit ___ (KAS-1), Schedules 1 and 2.

Q. Explain the difference between the Company's proposal and Staff's proposal in terms of dollars.

A. Notwithstanding a true-up for actual rate case expense, the Company's proposal calls for pro forma adjustments which increase expenses by $50,000 and increase the rate base by $125,000. My proposal decreases the Company's adjustment by $32,000 of annual operating expense and $80,000 in rate base. Details can be found on Exhibit ___ (KAS-1) Schedule 1.

Q. Does your proposed adjustment allow for a reasonable return?

A. Yes. The method that I am proposing allows for a reasonable return of the rate case expense and a return on the unamortized portion of the expense through rates over a five-year period.

Q. Is the Company proposing a true-up of rate case expense?

A. Yes, Company Witness Hitchcock proposed a true-up in his pre-filed testimony.

Q. Explain what true-up means.

A. Both Company's proposal and my proposal are based on estimates of what the actual rate case expense will be. A true-up means that these estimates would be changed to actual expense after the case is complete and actual expenses are known. Thus, rates would be based on actual expenses, not estimates.

Q. Do you agree with the proposed true-up?

A. I agree with the theory of the true-up method. However, the downfall to the true-up theory is that the actual expenses are unknown until some time after the case is complete and the docket is closed. Actual rates would remain unknown until such time. In addition, the actual setting of rates adds additional rate case expense which would lead to a subjective cut off date or another estimate which is in conflict with a true-up theory. Therefore, I do not agree that a true-up should be used for rate case expense for this docket. I believe that my estimate of rate case expense is reasonable and materially accurate for rate making purposes.

OFFICE SPACE ALLOCATION

Q. As part of your site review, did you tour NWPS's Market Street building in Huron, South Dakota?

A. Yes. While performing the site review, an NWPS employee gave Commission Staff a tour of the building.

Q. Based on information gathered during the tour, is it your observation that this building is used predominately by the public utility?

A. Yes, that is my observation.

Q. Did you observe any non-NWPS activities or employees stationed in the building?

A. Yes. During the tour I observed an office which contained cubicles for two NorCom employees and I observed a NorCom van parked in one of the west truck bays. The tour guide also informed me that some of the call center representatives take calls for NWPS's affiliate companies.

Q. Did staff obtain any other information pertaining to non-NWPS employees located in the Market Street building?

A. Yes. Data response 6-11 states that five NorthWestern Service employees and two NorCom employees occupy office space in the Market Street Building. Discussions with NWPS employees Bobbie Schroeppel, Support Services Team Leader, and Monte Bertsch, Call Center Manager reaffirmed that five NorthWestern Service and two NorCom employees were working in the Market Street building and identified that two of the 20 call center representatives handle Blue Dot Services Inc. (a NWPS affiliate) calls.

Q. Is the Market Street building included in rate base?

A. In data response 6-11, the Company states, "The Market Street building is included in rate base."

Q. Does NWPS receive rent from any of these affiliate companies?

A. In data response 6-11, the Company states, "NWPS did not receive rent for this space in the test year."

Q. What is the impact of this information?

A. Based on the information received, it appears that NWPS is supporting activities of non-regulated affiliate companies by providing office space without receiving any rent revenue or reimbursement of office space costs from the affiliate companies.

Q. What do you propose?

A. I propose a pro forma adjustment of $3,444.54 which increases NWPS's rent revenue received from its non-regulated affiliate companies.

Q. How did you arrive at this amount?

A. Based on data responses 2-44 and 6-11 and discussions with NWPS employees Schroeppel and Bertsch, I calculated that 1,842 square feet of office space should be allocated to non-NWPS employees. I then multiplied this amount by $10. Details for my adjustment can be found on Exhibit ___ (KAS – 2), Schedule 1.

Q. Is $10 per square foot a reasonable amount?

A. Based on the condition of the building and information collected, I believe $10 per month to be a conservative and reasonable amount.

Q. Does this conclude your testimony?

A. Yes.

NorthWestern Public Service
South Dakota - Gas
Rate Case Expense
Test Year Ending December 31, 1998

Exhibit ___
Schedule 1
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
		STAFF'S RECOMMENDATION			NWPS	
1		Base		Adjusted	Adjusted	
2	Description	Year	Adjustments	Base Year	Base Year	Differe
3						
4						
5	Past Rate Case Expense					
6	Yet Unamortized	$ 0	$ 0	$ 0	$ 0	$
7						
8	Company Consultant and					
9	Other Outside Expenses	0	20,000	20,000	50,000	(30
10						
11	SDPUC Rate Case Expense	0	70,000	70,000	100,000	(30
12						
13	TOTAL RATE CASE EXPENSE	$ 0	$ 90,000	$ 90,000	$ 150,000	$ (60
14						
15	Amortization - Annual Expense			$ 18,000	$ 50,000	$ (32
16						
17	Net Adjustment to Rate Base			$ 45,000	$ 125,000	$ (80

Sources:
Column c, line 9: Data Response 5-01, Company Witness Hitchcock and Witness Senger testimony
Column c, line 11: Contract between SDPUC and CRC and NG98-011 SDPUC billing
Column d, line 15: Staff Exhibit ___ (KAS-1), Schedule 2, line 7
Column d, line 17: Staff Exhibit ___ (KAS-1), Schedule 2, line 17
Column e: Company Exhibit___(TPH-1), Schedule No. 8

NorthWestern Public Service
South Dakota - Gas
Rate Case Expense
Test Year Ending December 31, 1998

Exhibit __
Schedule
Page 1 of

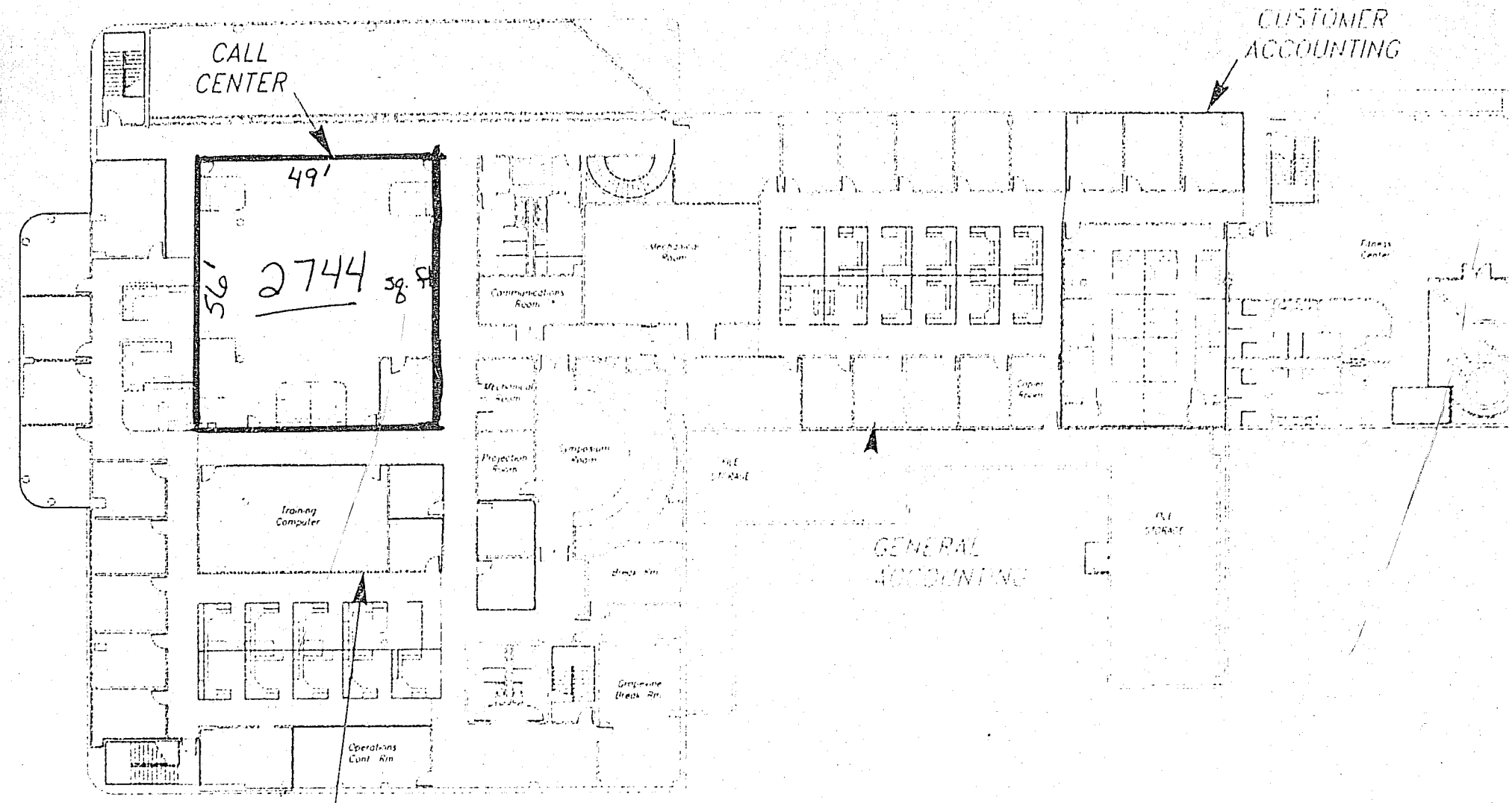
	(a)	(b)	(c)	(d)	(e)	(f)
1		**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Y**
2						
3	**Unamortized Portion**					
4	**(Beginning Balance)**	$ 90,000	$ 72,000	$ 54,000	$ 36,000	$ 1
5						
6	**Amortization Amount Per Year**					
7	**(Five-Year Amortization Period)**	18,000	18,000	18,000	18,000	1
8						
9	**Unamortized Portion**					
10	**(Ending Balance)**	$ 72,000	$ 54,000	$ 36,000	$ 18,000	$
11						
12	**Yearly Average Unamortized**					
13	**Balance**	$ 81,000	$ 63,000	$ 45,000	$ 27,000	$
14						
15	**Adjustment to Rate Base**					
16	**(Five-Year Average**					
17	**Unamortized Balance)**	$ 45,000				

Sources:
Column b, line 3: Staff Exhibit ___ (KAS-1), Schedule 1, column d, line 13
Line 7: Staff Exhibit ___ (KAS-1), Schedule 1, column d, line 13 divided 5 (years)
Line 13: (Line 4 plus line 10 divided) divided by 2
Column b, line 17: (Sum of line 13) divided by 5

NorthWestern Public Service
South Dakota - Gas
Space Allocation
Test Year Ending December 31, 1998

	(a)	(b)	(c)
1	**NorCom Employees**		
2	Square ft allocated to NorCom		1400
3	**NorthWestern Service**		
4	Square ft allocated to NorthWestern Service		172
5	**Blue Dot Employees**		
6	Call Center square ft	2700	
7	Call Center Reps.	20	
8	Square ft per Rep.	135	
9	Blue Dot Reps	2	
10	Square ft allocated to Blue Dot		270
11	TOTAL SPACE ALLOCATION		1842
12	Rent chargeable per Square ft.		$10.00
13	**TOTAL RENT REVENUE**		**$18,420.00**
14	Gas Allocation (Composite 4 Factor)		34%
15	TOTAL GAS ALLOCATION		**$6,262.80**
16	South Dakota Allocation (Composite 4 Factor)		55%
17	**TOTAL SOUTH DAKOTA GAS ALLOCATION**		**$3,444.54**

Sources:
Line 2, column c: Staff Exhibit ___ (KAS-3), page 2
Line 4, column c: Data response 6-11
Line 6, column b: Staff Exhibit ___ (KAS-3), page 1
Line 7, column b: Monty Bertsch; NWPS Call Center Manager
Line 9, column b: Monty Bertsch; NWPS Call Center Manager
Line 14, column c: Company Exhibit___(TPH-1), Schedule No. 10
Line 16, column c: Company Exhibit___(TPH-1), Schedule No. 10



SECOND FLOOR PLAN

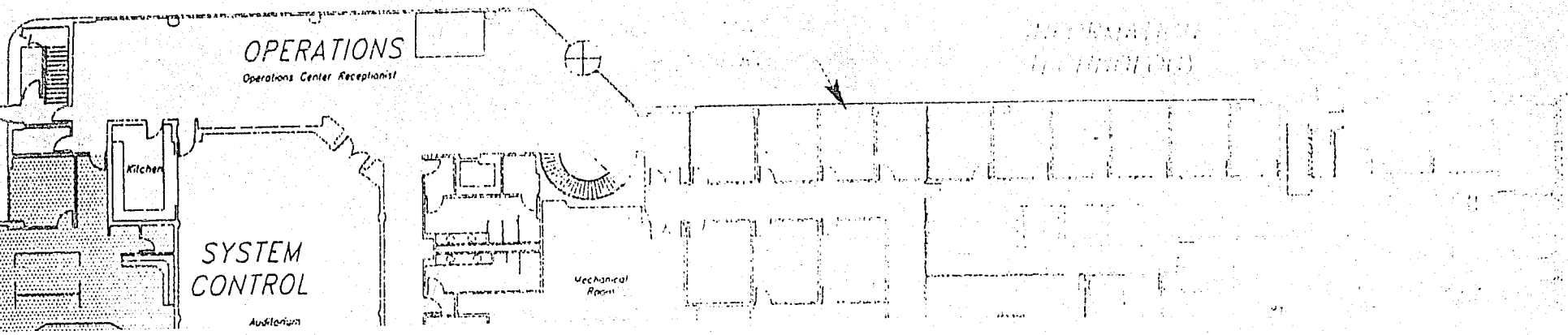
SCALE: 1" = 30'

NorthWestern Operations Center

600 Market St. W., Huron, S.D. 57350

Source:
Company data response 2-44

08/09/99


OPERATIONS
Operations Center Receptionist
Kitchen
SYSTEM
CONTROL
Auditorium
Mechanical
Room

FAX Received OCT 08 1999

RECEIVED

OCT 12 1999

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**REQUEST FOR SUSPENSION OF PROCEDURAL SCHEDULE** **DOCKET NO. NG99-002**

Whereas, an order and notice of hearing dated August 3, 1999 set October 8, 1999 as the time for NorthWestern Public Service to submit its rebuttal testimony in this matter;

Pursuant to the agreement between the parties at the Commission hearing, that the rebuttal testimony deadline would be October 13, 1999 and also for the reason that the parties are nearing settlement in this matter, NorthWestern Public Service requests that the procedural schedule be suspended and that it be allowed to file its rebuttal testimony by October 13, 1999.

Dated October 8, 1999

Russell C. Molstad, Jr.
Corporate Attorney

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	AMENDED ORDER FOR AND NOTICE OF HEARING NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 1-26-17.1, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21, and ARSD 20:10:01:15.02 and .03.

The procedural schedule for testimony shall be as follows:

DATE	PROCEDURAL SCHEDULE
September 24, 1999	Staff and Intervenors' Prefiled Testimony Due
October ~~8~~ 13, 1999	Rebuttal Testimony Due

On October 8, 1999, NWPS requested that the due date for the rebuttal testimony be changed from October 8, 1999 to October 13, 1999. The Commission grants the request. A hearing shall be held at 9:00 a.m., on Wednesday, October 20, 1999, and Thursday, October 21, 1999, in Room ~~412~~413, State Capitol Building, 500 East Capitol, Pierre, South Dakota. The hearing is open to the public. All persons so testifying shall be subject to cross-examination.

The issue at the hearing is whether the Commission shall grant NWPS' request to implement revised natural gas rate schedules designed to produce additional revenues of $2,108,112.

The hearing shall be an adversary proceeding conducted pursuant to SDCL Chapter 1-26. All parties have the right to be present and to be represented by an attorney. These rights and other due process rights shall be forfeited if not exercised at the hearing. If you or your representative fail to appear at the time and place set for the hearing, the Final Decision will be based solely on the testimony and evidence provided, if any, during the hearing or a Final Decision may be issued by default pursuant to SDCL 1-26-20. After the hearing the Commission will consider all evidence and testimony that was presented at the hearing. The Commission will then enter Findings of Fact, Conclusions of Law, and a Final Decision regarding this matter. As a result of this hearing, the Commission shall determine whether it shall grant NWPS' request to implement revised rate schedules. The Commission's Final Decision may be appealed by the parties to the state Circuit Court and the state Supreme Court as provided by law. It is therefore

ORDERED that the procedural schedule set forth above shall be followed by all parties to these proceedings. It is further

ORDERED that the hearing shall commence at 9:00 a.m., on Wednesday, October 20, 1999, in Room 412, State Capitol Building, 500 East Capitol, Pierre, South Dakota, and if necessary, shall continue through Thursday, October 21, 1999.

Pursuant to the Americans with Disabilities Act, this hearing is being held in a physically accessible location. Please contact the Public Utilities Commission at 1-800-332-1782 at least 48 hours prior to the hearing if you have special needs so arrangements can be made to accommodate you.

Dated at Pierre, South Dakota, this ~~3rd~~ 12th day of ~~August~~ October, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Melanie Kaebo

Date: 10/12/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg

JAMES A. BURG, Chairman

Pam Nelson

PAM NELSON, Commissioner

Laska Schoenfelder

LASKA SCHOENFELDER, Commissioner

NorthWestern™
PUBLIC SERVICE

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Facsimile 605-353-7519
Internet: www.northwestern.com

October 13, 1999

RECEIVED
OCT 14 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms Karen Cremer
S.D. Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Rebuttal Testimony of Thomas P. Hitchcock

FAX Received OCT 13 1999

Dear Karen,

Enclosed please find an original and twelve copies of the Rebuttal Testimony of Thomas P. Hitchcock. If you have any questions, please feel free to contact me. I will fax a copy of the Rebuttal Testimony of Mr. Hitchcock to Mr. Towers.

I will be filing the original and twelve copies tomorrow morning when I am in Pierre, however, I wanted to file by fax the Rebuttal Testimony today.

I will await your comments and position on the Nekota matter.

Thank you very much.

Sincerely yours,

Russell C. Molstad, Jr.

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Tom Hitchcock
Alan Dietrich
Rod Leyendecker
Jeff Decker

FAX Received OCT 13 1999

RECEIVED
OCT 14 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE, A DIVISION OF NORTHWESTERN CORPORATION FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	Docket No. NG99-002

REBUTTAL TESTIMONY
OF
THOMAS P. HITCHCOCK

Q. Please state your name.

A. My name is Thomas P. Hitchcock.

Q. Are you the same Thomas P. Hitchcock that provided direct testimony in this proceeding?

A. Yes, I am.

Q. Please state the nature of your rebuttal testimony in this proceeding.

A. The purpose of my rebuttal testimony is to set forth information in response to the direct testimony filed by witness Robert G. Towers, on behalf of the Commission Staff, which recommends that certain costs incurred in the charge imposed on NorthWestern Public Service ("NPS") by its affiliate NorthWestern Energy Corporation ("NEC") for the use of pipeline capacity be disallowed. Mr. Towers recommends that since NPS is collecting these pipeline charges through the PGA the adjustment he proposes should be implemented as a reduction in the PGA rather than base rates.

Q. Do you agree with Mr. Tower's assertion that this is a PGA issue?

A. Yes, I do. NPS currently tracks the pipeline charges through its PGA mechanism.

Q. Have you prepared any exhibits in support of your rebuttal testimony?

A. Yes, I am sponsoring three exhibits related to my rebuttal testimony in this case. Exhibit__(TPH-3) sets forth information related to NorthWestern's February 1, 1996 system peak day, Exhibit__(TPH-4) shows the derivation of the actual test year return that the NorthWestern partner entities achieved on the 1996 Aberdeen pipeline capacity project and Exhibit___(TPH-5) shows the additional capacity release revenues generated by NPS for the year following the first flow on the newly constructed pipeline.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes, they were.

Q. Do these exhibits reflect the information shown on NorthWestern's books and records?

A. Yes.

Q. The witness for the Commission Staff, Mr. Towers, has proposed a significant decrease in the annual charges for capacity paid by NPS to NEC for the 1996 pipeline capacity project, which included construction of a pipeline, owned by NEC's affiliate Nekota Resources, Inc., from Northern Border Pipeline Company ("NBPL") to the City of Aberdeen. Do you agree with such adjustment?

A. No. I would like to elaborate on the issues that led to the construction of the pipeline and the various actions that were undertaken by NPS and NEC prior to such pipeline construction. I believe that those actions benefited NPS and its customers immensely.

In 1996 NPS had in effect an agreement with Northern Natural Gas Company ("NNG") for pipeline capacity for its South Dakota operations, with a number of delivery points from the NNG interstate pipeline facilities at various town border stations ("TBS") in eastern South Dakota, including Aberdeen. The Aberdeen TBS was at the end of the NNG pipeline, and operational problems were developing. One of these operational problems was the use of natural gas upstream of the Aberdeen TBS for the Northern States Power Company Pathfinder electric generating plant. As the Pathfinder plant needed large quantities of natural gas to meet its peaking needs, it caused a decrease in pipeline pressure downstream, affecting service to NPS' Aberdeen TBS. As the Pathfinder plant's needs were growing, NPS was concerned that the reliability of service to its customers might be compromised, therefore NPS officials visited with NNG pipeline executives about ways to enhance delivery to downstream communities. NNG's proposed solutions were expensive and expected to be effected in later years, with no relief in the near term.

Additionally, based on extreme cold weather conditions on February 1, 1996, NPS was concerned about the level of primary firm capacity it held on NNG to serve firm gas loads. Exhibit___(TPH-3) sets forth certain peak day information, and shows that primary firm capacity on NNG was over 10,000 MMBtu short of meeting firm loads on February 1, 1996. The shortfall was supplemented by secondary firm (capacity released by others) and propane peak shaving. Secondary firm capacity could become unavailable, at any price, under certain weather and pipeline operating conditions.

Q. **What does the data on this exhibit show concerning the Aberdeen TBS?**

A. NPS had 10,358 MMBtu of firm capacity contracted with NNG allocated to the Aberdeen TBS, yet the peak day sendout was 19,500 MMBtu. Being aware of NNG's above-mentioned pipeline pressure problems, any NEC proposed solution had to deal with Aberdeen's growing gas demand.

In order to meet these challenges, NPS and NEC executives began researching alternatives and found the construction of a new pipeline between NBPL and Aberdeen as the best solution, if contractual commitments to NNG could be renegotiated.

Q. What were these contractual commitments?

A. Among the commitments that NPS had to NNG was the requirement to use NNG as its exclusive pipeline facility in South Dakota. Pursuant to a November 20, 1990 Letter Agreement, NPS was required to "maintain existing firm entitlement levels for a minimum of ten years and utilize Northern's system for all throughput for ten years for communities currently served by Northern".

Once the alternative pipeline plan had been developed, NPS and NEC executives negotiated with NNG for ways to solve the deliverability problem at Aberdeen and the need to have competitively priced, and reliable, gas service to South Dakota customers.

NNG was unwilling to change the deliverability solution implementation plan to an earlier schedule or to discount its transportation charges sufficiently to be a workable alternative to the new pipeline. NNG, NPS and NEC did agree to the following solution:

(1) NPS would be allowed to transfer its NNG delivery requirements to Aberdeen to other town border stations on the NPS system;

(2) NEC, through its wholly owned subsidiary Nekota Resources, Inc., could

construct a pipeline facility from NBPL to Aberdeen to serve NPS, as well as NEC customers, and NPS would be free from its exclusive pipeline obligation to NNG, enabling NPS to purchase pipeline capacity from its affiliate company at Aberdeen;

(3) NEC would buy firm capacity of 5,000/MMBtu/day from NNG;

(4) NEC would buy 300,000 MMBtu of firm deferred delivery service capacity from NNG.

Q. What are the benefits to NPS resulting from the NEC negotiations with NNG?

A. The outcome had a number of benefits for NPS and its customers. They were and are:

(1) The deliverability (pressure) problem for NPS at Aberdeen would be eliminated because service would come directly from NBPL, through the Nekota pipeline facility, to NPS' Aberdeen TBS, and NBPL did not have the pressure problem at the tap that NNG had in its service line to Aberdeen;

(2) NPS would receive transportation charges that were discounted below what NNG was willing to charge;

(3) NNG would not assert any contractual limitations on NPS receiving pipeline service from anyone other than NNG;

(4) While the Nekota pipeline was constructed to transport more than NPS' firm capacity needs on a daily basis (as formerly committed to NNG), the entire Nekota pipeline capacity would be dedicated fully to NPS, with NEC using only released or excess capacity on days that NPS did not need

such capacity;

(5) For any capacity that NPS needs above its contracted commitment to NEC, NPS is responsible to pay for such capacity only on the days that such capacity is needed, on a 100% load factor basis or minimal charge;

(6) NEC would assume the new obligations that had been made to NNG, with no commitment or market risk by NPS or its customers;

(7) Enhances NPS' ability to keep interruptible loads on line, even when NNG calls operational alerts. This maintains NPS' distribution margins due to continuation of gas deliveries to interruptible gas users, with the added benefit of customers avoiding the inconvenience of an interruption in natural gas service;

(8) NPS avoids paying NNG transportation fuel and variable commodity costs by using the Northern Border Pipeline only and bypassing NNG's system. This is estimated to save over $100,000 annually in gas costs;

(9) NPS would have additional firm capacity to release into the markets.

Q. Please expand on this last benefit point.

A. Exhibit___(TPH-5) sets forth the value for capacity release transactions NPS received one year before and one year after the new pipeline to Aberdeen was put into service. Because NPS had more available pipeline capacity on NNG, additional capacity release deals were completed. Over $200,000 of additional capacity release revenue credits were available to NPS gas sales customers through the PGA.

Q. Please continue with your discussion of the benefits.

A. In summary, NPS has an obligation to pay NEC less than it formerly paid NNG, with additional capacity available (up to the pipeline's full capacity limit) all year long, and paying for such additional capacity only on the days its needs it. NEC has assumed various commitments to NNG to enable NPS to have these advantages, at no cost to NPS. In short, this arrangement has been to the advantage of NPS, its customers, NNG, NEC, and Nekota. Through a series of creative steps, NPS and NEC have brought benefits of alternative pipeline construction without resorting to litigation or Federal regulatory delays and uncertainty.

Q. What does Mr. Towers base his proposed cost adjustment on?

A. Mr. Towers attempts to carve from this creative solution only the pipeline construction costs, and then he mistakenly seeks to limit the appropriate capacity charge to the proposed NPS rate of return for such pipeline. In the South Dakota Supreme Court case, In the Matter of the Application of Montana-Dakota Utilities Company, 278 N.W.2d 189 (S.D. 1979), the Supreme Court rejected a similar argument, stating that the rate of return of an affiliated coal company should not be held to the same rate of return as a public utility. The Court reasoned that the coal companies were not subject to the authority of the Commission, and that the appropriate rate of return for a coal company is certainly different from that of a public utility. The case was remanded to the Commission to determine an appropriate rate of return consistent with the coal industry.

Similarly, here the Nekota pipeline is not an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A) because Nekota only serves its parent companies, NEC and NPS. Its charges to NPS, pursuant to their contract (which charges have been

included in NPS' monthly PGA filings since 1996), are subject to Commission scrutiny under SDCL 49-34A-19.2. However, as detailed above, NEC has incurred significant obligations to provide NPS with this favorable capacity arrangement. NPS and NEC both believe that the charges paid by NPS are fair and reasonable, and the arrangement provides significant benefits to NPS and its customers, which the prior arrangement with NNG did not provide. To adopt the Staff's position on this issue would negatively influence other future creative solutions, to the ultimate detriment to NPS and its customers.

Q. Have you prepared an analysis of test year results for all the costs incurred to provide service under the 1996 pipeline capacity project?

A. Yes, I have. This is shown on Exhibit__(TPH-4).

Q. What does the analysis demonstrate?

A. Based on test year ended December 31, 1998 actual results, and inclusive of all reasonable costs of providing service, the return on equity for this project was 12.34%. This is not an unreasonable return or profit for this type of activity.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

NORTHWESTERN PUBLIC SERVICE

Exhibit___(TPH-3)

February 1, 1996 System Peak Day Information
Summary of All Customer Usage
Volumes in MMBtu

SENDOUT AND COMPARISION TO PRIMARY FIRM PIPELINE CAPACITY

Location	NNG Primary Firm MDQ	Total Sendout	Third Party Sendout	NWPS Sendout	NWPS Sendout Over NNG Firm MDQ
Aberdeen #1	10,358	19,500	0	19,500	9,142
Mitchell #1	4,715	10,869	0	10,869	6,154
Brookings #1	4,939	9,150	672	8,478	3,539
Huron #1	7,390	10,700	46	10,654	3,264
Madison #1	1,900	4,400	0	4,400	2,500
Redfield #1	865	2,256	0	2,256	1,391
Bryant #1	153	1,336	0	1,336	1,183
Volga #1	254	957	0	957	703
De Smet #1	445	1,017	0	1,017	572
Clark #1	365	910	0	910	545
McCain Foods	300	698	0	698	398
Howard #1	365	750	0	750	385
Arlington #1	309	611	0	611	302
Lake Preston #1	210	498	0	498	288
Alexandria #1	178	356	0	356	178
Frankfort #1	50	191	0	191	141
Doland #1	120	243	0	243	123
Conde #1	77	174	0	174	97
Willow Lake #1	133	229	0	229	96
Oldham #1	77	134	0	134	57
Yale #1	17	64	0	64	47
Spencer #1	123	155	0	155	32
Farm Taps/Misc	0	26	0	26	26
Hazel #1	50	74	0	74	24
Raymond #1	30	51	0	51	21
Turton #1	50	70	0	70	20
Vienna #1	27	46	0	46	19
Parker #1	2,163	972	21	951	(1,212)
Parkston #1	3,602	2,195	0	2,195	(1,407)
Webster #1	3,605	1,626	0	1,626	(1,979)
Milbank #1	6,413	3,921	0	3,921	(2,492)
Totals	49,283	74,179	739	73,440	24,157

SENDOUT AND CAPICITY SOURCE

Description	Total	Firm	Interruptible
NWPS Customer Sales	71,207	59,582	11,625
3.04% Dist. Use and Loss	2,233	1,868	365
NWPS Sendout	73,440	61,450	11,990
Source of Capacity:			
NNG Primary Firm	49,283	49,283	0
NNG Secondary Firm	20,434	8,444	11,990
NWPS Peak Shaving	3,723	3,723	0
Total Capacity Source	73,440	61,450	11,990

NWPS CUSTOMER SALES

Rate 84 Firm Tariff Sales	3,265	3,265	0
Rate 88 Firm Agency Sales	539	539	0
Rate 84 Overrun Tariff Sales	2,006	0	2,006
Rate 88 Overrun Agency Sales	2,077	0	2,077
Rate 85 Inter. Tariff Sales	2,498	0	2,498
Rate 89 Inter. Agency Sales	5,044	0	5,044
Rate 81/82 Firm Tariff Sales	55,778	55,778	0
Total Customer Sales	71,207	59,582	11,625

H:\DATA\RATES\PEAK2196.WK4

NorthWestern Partner Entities
1996 Pipeline Capacity Project
Determination of Return on Investment
Test Year Ended December 31, 1998

Line No.	Description	Amounts
	(a)	(b)
1	**Cost of Service - Warner Pipeline @**	
2	**Regulated Rates of Return Approved**	
3	**in NPS Docket No. NG94-008**	
4	Capital Component Ratio	
5	Long-term debt	52.44%
6	Preferred stock	1.13%
7	Common stock	46.43%
8	Capital Component Rate	
9	Long-term debt	7.28%
10	Preferred stock	4.52%
11	Common stock	11.25%
12	Capital Component Weighted Cost	
13	Long-term debt	3.82%
14	Preferred stock	0.05%
15	Common stock	5.22%
16	Overall	9.09%
17	Income Taxes on Return	2.84%
18	Pre-tax Return	11.93%
19	Actual Capital Cost	$1,185,397.04
20	Levelized Pre-tax Operating Income - 20 YR	$158,003.70
21	**Test Year Actual Rates of Return**	
22	**Utilizing Capital Structure and Embedded**	
23	**Debt and Preferred Stock Costs Approved**	
24	**in NPS Docket No. NG94-008**	
25	Capital Component Ratio	
26	Long-term debt	52.44%
27	Preferred stock	1.13%
28	Common stock	46.43%
29	Capital Component Rate	
30	Long-term debt	7.28%
31	Preferred stock	4.52%
32	Common stock	12.34%
33	Capital Component Weighted Cost	
34	Long-term debt	3.82%
35	Preferred stock	0.05%
36	Common stock	5.73%
37	Overall	9.60%
38	Income Taxes on Return	3.11%
39	Pre-tax Return	12.71%
40	Actual Capital Cost	$1,185,397.04
41	Test Year Pre-tax Operating Income - 20 YR Average	$165,843.78

NorthWestern Partner Entities
1996 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	January	February	March	April	May	June
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Revenues**						
2	MDQ - MMBtus:						
3	NPS Aberdeen Primary Firm Capacity	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0
4	NPS Aberdeen Secondary Firm Capacity	0.0	0.0	0.0	0.0	0.0	0.0
5	NEC Aberdeen Secondary Firm Capacity	1,898.4	1,615.0	1,761.3	1,240.0	1,254.8	1,163.3
6	NEC Northern Natural Primary Firm Capacity	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0
7	Transfer Rate	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20
8	Transfer Revenues:						
9	NPS Aberdeen Primary Firm Capacity	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00
10	NPS Aberdeen Secondary Firm Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	NEC Aberdeen Secondary Firm Capacity	$6,074.88	$5,168.00	$5,636.16	$3,968.00	$4,015.36	$3,722.56
12	NEC Northern Natural Primary Firm Capacity	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00
13	Total Revenues	$70,074.88	$69,168.00	$69,636.16	$67,968.00	$68,015.36	$67,722.56
14	**Expenses**						
15	Northern Natural Gas Services:						
16	Primary Firm Pipeline Capacity						
17	Demand Charges	$22,435.00	$22,435.00	$22,360.00	$19,385.00	$19,715.00	$19,715.00
18	Commodity Charges	$10,943.00	$9,884.00	$10,850.00	$4,500.00	$4,650.00	$4,500.00
19	Fuel Reimbursement	$6,794.27	$5,542.88	$6,731.65	$6,605.40	$6,731.65	$4,474.94
20	Firm Deferred Delivery						
21	Capacity & Reservation Charges	$7,653.61	$7,653.61	$7,653.61	$7,653.61	$7,653.61	$26,025.61
22	Injection / Withdrawal Charges	$1,575.30	$575.36	$576.33	$338.61	$0.00	$799.87
23	Fuel Reimbursement	$0.00	$0.00	$0.00	$0.00	$0.00	$955.39
24	NEC Management Fees	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00
25	1998 Property Taxes - Paid in 1999	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85
26	Total Expenses	$55,345.03	$52,034.70	$54,115.44	$44,426.47	$44,694.11	$62,414.66
27	**Pre-tax Operating Income**	$14,729.85	$17,133.30	$15,520.72	$23,541.53	$23,321.25	$5,307.90

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NorthWestern Partner Entities
1998 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	July	August	September	October	November	December	Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Revenues**							
2	MDQ - MMBtus:							
3	NPS Aberdeen Primary Firm Capacity	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	180,000.0
4	NPS Aberdeen Secondary Firm Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	NEC Aberdeen Secondary Firm Capacity	1,103.2	1,085.5	1,203.3	1,706.5	1,966.7	1,980.6	17,978.6
6	NEC Northern Natural Primary Firm Capacity	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	60,000.0
7	Transfer Rate	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20
8	Transfer Revenues:							
9	NPS Aberdeen Primary Firm Capacity	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$576,000.00
10	NPS Aberdeen Secondary Firm Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	NEC Aberdeen Secondary Firm Capacity	$3,530.24	$3,473.60	$3,850.56	$5,460.80	$6,293.44	$6,337.92	$57,531.52
12	NEC Northern Natural Primary Firm Capacity	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$192,000.00
13	Total Revenues	$67,530.24	$67,473.60	$67,850.56	$69,460.80	$70,293.44	$70,337.92	$825,531.52
14	**Expenses**							
15	Northern Natural Gas Services:							
16	Primary Firm Pipeline Capacity							
17	Demand Charges	$19,580.00	$19,580.00	$19,580.00	$19,580.00	$19,710.00	$19,710.00	$243,785.00
18	Commodity Charges	$4,650.00	$4,650.00	$4,500.00	$4,650.00	$10,515.00	$10,865.50	$85,157.50
19	Fuel Reimbursement	$5,442.76	$4,431.27	$3,635.89	$4,623.94	$3,859.00	$4,246.79	$63,120.44
20	Firm Deferred Delivery							
21	Capacity & Reservation Charges	$26,025.61	$26,025.61	$26,025.61	$26,025.61	$7,768.08	$7,768.08	$183,932.26
22	Injection / Withdrawal Charges	$967.22	$551.22	$666.62	$829.35	$251.71	$651.08	$7,782.67
23	Fuel Reimbursemont	$1,359.84	$630.94	$646.93	$990.53	$0.00	$0.00	$4,583.63
24	NEC Management Fees	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$48,000.00
25	1998 Property Taxes - Paid in 1999	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.89	$23,326.24
26	Total Expenses	$63,969.28	$61,812.89	$60,998.90	$62,643.28	$48,047.64	$49,185.34	$659,687.74
27	**Pre-tax Operating Income**	$3,560.96	$5,660.71	$6,851.66	$6,817.52	$22,245.80	$21,152.58	$165,843.78

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NorthWestern Partner Entities
1996 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	January	February	March	April	May	June
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Fuel Reimbursement**						
2	Primary Firm Pipeline Capacity - NNG						
3	Monthly Receipts - MMBtus	155,000.0	140,000.0	155,000.0	150,000.0	155,000.0	150,000.0
4	Fuel Reimbursement %	1.98%	1.98%	1.98%	1.98%	1.98%	1.53%
5	Fuel Gross-up - MMBtus	158,131.0	142,828.0	158,131.0	153,030.0	158,131.0	152,330.7
6	Fuel Reimbursement - MMBtus	3,131.0	2,828.0	3,131.0	3,030.0	3,131.0	2,330.7
7	IFFOM-Ventura Rate per MMBtu	$2.17	$1.96	$2.15	$2.18	$2.15	$1.92
8	Fuel Reimbursement - $	$6,794.27	$5,542.88	$6,731.65	$6,605.40	$6,731.65	$4,474.94
9	Firm Deferred Delivery - NNG						
10	Injection Volumes - MMBtus	0.0	0.0	0.0	0.0	0.0	62,490.0
11	Fuel Reimbursement %	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%
12	Fuel Gross-up - MMBtus	0.0	0.0	0.0	0.0	0.0	62,987.6
13	Fuel Reimbursement - MMBtus	0.0	0.0	0.0	0.0	0.0	497.6
14	IFFOM-Ventura Rate per MMBtu	$2.17	$1.96	$2.15	$2.18	$2.15	$1.92
15	Fuel Reimbursement - $	$0.00	$0.00	$0.00	$0.00	$0.00	$955.39

		July	August	September	October	November	December	Year
		(b)	(c)	(d)	(e)	(f)	(g)	(h)
16	Primary Firm Pipeline Capacity - NNG							
17	Monthly Receipts - MMBtus	155,000.0	155,000.0	150,000.0	155,000.0	150,000.0	155,000.0	1,825,000.0
18	Fuel Reimbursement %	1.53%	1.53%	1.53%	1.53%	1.27%	1.27%	1.67%
19	Fuel Gross-up - MMBtus	157,408.3	157,408.3	152,330.7	157,408.3	151,929.5	156,993.8	1,856,060.6
20	Fuel Reimbursement - MMBtus	2,408.3	2,408.3	2,330.7	2,408.3	1,929.5	1,993.8	31,060.6
21	IFFOM-Ventura Rate per MMBtu	$2.26	$1.84	$1.56	$1.92	$2.00	$2.13	$2.03
22	Fuel Reimbursement - $	$5,442.76	$4,431.27	$3,635.89	$4,623.94	$3,859.00	$4,246.79	$63,120.44
23	Firm Deferred Delivery - NNG							
24	Injection Volumes - MMBtus	75,564.0	43,064.0	52,080.0	64,793.0	0.0	0.0	297,991.0
25	Fuel Reimbursement %	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%
26	Fuel Gross-up - MMBtus	76,165.7	43,406.9	52,494.7	65,308.9	0.0	0.0	300,363.8
27	Fuel Reimbursement - MMBtus	601.7	342.9	414.7	515.9	0.0	0.0	2,372.8
28	IFFOM-Ventura Rate per MMBtu	$2.26	$1.84	$1.56	$1.92	$2.00	$2.13	$1.93
29	Fuel Reimbursement - $	$1,359.84	$630.94	$646.93	$990.53	$0.00	$0.00	$4,583.63

Exhibit___(TPH-5)

WARNER LINE BENEFIT TO
NORTHWESTERN UTILITY OPERATIONS
Additional Northern Natural Gas Firm Capacity Releases

Production Month	Capacity Release Credits	Production Month	Capacity Release Credits	Capacity Release Benefit
Nov. 96	$43,486.97	Nov. 95	$2,042.07	$41,444.90
Dec. 96	$36,332.87	Dec. 95	$4,184.72	$32,148.15
Jan. 97	$28,405.72	Jan. 96	$7,897.21	$20,508.51
Feb. 97	$39,113.98	Feb. 96	$5,713.38	$33,400.60
Mar. 97	$34,859.08	Mar. 96	$9,136.32	$25,722.76
Apr. 97	$70,254.79	Apr. 96	$7,210.71	$63,044.08
May 97	$39,260.83	May 96	$9,084.32	$30,176.51
Jun. 97	$15,393.08	Jun. 96	$24,411.42	($9,018.34)
Jul. 97	$8,752.99	Jul. 96	$22,535.79	($13,782.80)
Aug. 97	$3,652.59	Aug. 96	$11,038.79	($7,386.20)
Sep. 97	$11,452.10	Sep. 96	$26,419.77	($14,967.67)
Oct. 97	$33,832.13	Oct. 96	$30,540.78	$3,291.35
Totals	$364,797.13	Totals	$160,215.28	$204,581.85

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AFFIDAVIT

STATE OF SOUTHDAKOTA)
) ss
COUNTY OF BEADLE)

I, Thomas P. Hitchcock, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Thomas P. Hitchcock

Thomas P. Hitchcock

Subscribed and sworn to before me this 12th day of October, 1999.

Stacie Dowling

Notary Public in and for the State of South Dakota

Sept. 26, 2004



NorthWestern™
CORPORATION

Alan D. Dietrich
Vice President – Legal Administration
Telephone (605) 978-2907

125 S. Dakota Avenue
Suite 1100
Sioux Falls, SD 57104-6403
Telephone 605-978-2908
Facsimile 605-978-2910
Internet: www.northwestern.com

October 13, 1999

Mr. William Bullard
Executive Director
SD Public Utilities Commission
500 East Capitol
Pierre, SD 57501

FAX Received OCT 13 1999

RECEIVED
OCT 15 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Re: Application of NorthWestern Public Service
Docket NG99-002

Dear Mr. Bullard:

I am enclosing an original and 12 copies of the Rebuttal Testimony of Michael J. Hanson in the above matter on behalf of NorthWestern. Additional Rebuttal Testimony is being sent in this matter under separate cover from the Huron office of NorthWestern.

Sincerely yours,

Alan D. Dietrich
Vice President – Legal Administration

CC: Thomas Hitchcock
Rodney Leyendecker
Michael Hanson
Russell Molstad

FAX Received OCT 13 1999

RECEIVED
OCT 15 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE, A DIVISION OF NORTHWESTERN CORPORATION FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	**Docket No. NG99-002**

REBUTTAL TESTIMONY
OF
MICHAEL J. HANSON

Q. Please state your name.

A. My name is Michael J. Hanson.

Q. Are you the same Michael J. Hanson that provided direct testimony in this proceeding?

A. Yes, I am.

Q. Please state the nature of your rebuttal testimony in this proceeding.

A. My rebuttal testimony covers two issues. First, I have reviewed the rebuttal testimony of Thomas P. Hitchcock in this matter, and the purpose of my rebuttal testimony is to state that, on behalf of NorthWestern Public Service ("NPS"), I agree with the statements and conclusions made by Mr. Hitchcock in that testimony. The contract for the delivery of natural gas to NPS' Aberdeen town border station that NPS entered in 1996 has brought significant benefits, both in reliability and in cost savings, to NPS and its customers. I believe that the arrangement has been and will be a fair and equitable solution for NPS

and its customers.

Second, in its testimony The PUC Staff has suggested that NorthWestern Public Service ("NPS") enter into written contracts with NorthWestern Corporation ("NOR") and each affiliate company that it does business with, that such contracts be "subject to the same general type of controls that the SEC requires of participants to service company agreements under the Public Utility Holding Company Act of 1935," and that NPS submit for Commission approval each of these contracts. I disagree with that approach.

Q. Why do you disagree with Staff's approach with regard to such contracts?

A. First, NPS is a division of NOR and therefore is part of the same legal entity. For NPS to enter into a contract with NOR would be one entity contracting with itself. Rather than doing so, NPS proposes continuing its efforts at detailed accounting to show the allocation of NOR expenses among the various departments and divisions of NOR, which are certainly subject to Commission oversight pursuant to SDCL 49-34A-19.1 and the Commission's regulations. NPS does plan to continue to formalize in written contracts its arrangements with each affiliate company, primarily NorthWestern Energy Corporation, NorthWestern Services Corporation, NorCom Advanced Technologies, Inc., and Nekota Resources, Inc. These contracts will detail the services to be provided between NPS and the affiliate company and the compensation to be paid for such services. A copy of each of these contracts will be provided to the Commission. NPS disagrees with Staff's position that these affiliate contracts must be entirely cost-based. Consistent with SDCL 49-34A-19.2 and the holding of the South Dakota Supreme Court in the case entitled, In the Matter of the Application of Montana-Dakota Utilities

Company, 278 N.W.2d 189 (S.D. 1979), the Commission may disallow an unreasonable profit paid for materials or services provided to a public utility by an affiliate company, but a utility affiliate is allowed a reasonable profit. Under the statute and the ruling of that case, the utility has the burden of showing that no unreasonable profit is involved, but to limit an affiliate of a utility to only its cost would be contrary to the statute and the Supreme Court's ruling. NPS is not a registered holding company subject to the SEC rules governing and severely limiting such companies' diversified activities. The nature of NOR's significant diversification is one of the reasons it has not taken steps to create a holding company structure. I would also note that each Congressional session, efforts have been undertaken to repeal the PUHCA as an antiquated and overly restrictive measure, given the more competitive utility industry in the United States. Furthermore, as Staff has testified, there is evidence suggesting that the charges for management services have not been overpriced to NPS by its affiliates. Certainly, the Commission and its Staff have ample opportunity to determine if any unreasonable charges are to be made, as they review the contracts that will be filed by NPS.

Q. **Does this conclude your rebuttal testimony?**

A. Yes, it does.

AFFIDAVIT

STATE OF SOUTH DAKOTA)
) ss
COUNTY OF MINNEHAHA)

I, Michael J. Hanson, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Michael J. Hanson

Subscribed and sworn to before me this 13th day of October, 1999.

Notary Public in and for the State of South Dakota
My Commission Expires: 3/6/2001

Chesapeake Regulatory Consultants, Inc.
10025 Governor Warfield Parkway, Suite 301-B
Columbia, MD 21044-3330

301/596.3103 FAX: 301/596.1471

Robert G. Towers
Beall L. Copeland, Jr.
David E. Petersen

FAX TRANSMISSION

Date 10/19/99

To: Dave Jacobson
Karen Gaar, Esq. No. 605 773 3809

Fm: Bob Towers Phone 301/596.3103
FAX 301/596.1471

Number of pages, inciuding this cover: 4

SUBJECT: Nelida

MESSAGE:

Also by e-mail to Karen.

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

NorthWestern Public Service
Application to Increase Gas Rates in South Dakota
Docket No. NG99-002

Additional Testimony of David A. Jacobson
on Behalf of the Commission Staff

October 20, 1999

Q. What is the purpose of your additional testimony at this time?

A. I will address an issue which was identified in Staff's review of Northwestern Public Service's ("NPS") base rate increase filing but which involves costs that are and have been, since 1996, recovered through its Purchased gas adjustment ("PGA") clause.

Q. What is the issue and what is your recommendation?

A. The issue involves payments made by NPS to its affiliate Northwestern Energy Company ("NEC") for the purchase of pipeline capacity from NEC's subsidiary, Nekota Resources ("Nekota"). The Nekota pipeline was constructed in 1996 and is used to transport gas received from Northern Border Pipeline to Aberdeen, South Dakota.

I am recommending that the charges passed through the PGA be reduced to a level that reflects Nekota's cost of providing the capacity. I also recommend that this adjustment be made effective retroactive to December, 1996 when the costs were first passed through the PGA. The annual adjustment, which is based on Nekota's actual investment in the transmission line, would reduce NPS' on-going PGA collections by $403,185 annually.

Q. Please explain these transactions more fully.

A. NPS' gas supply to Aberdeen enters the distribution system through two pipelines. One is a pre-existing connection to Northern Natural; the other is a pipeline owned by Nekota Resources, Inc. ("Nekota"), a subsidiary of NEC and, thereby, an affiliate of NPS. Nekota is connected to Northern Border Pipeline.

NEC entered into a contract with Nekota, dated November 1, 1996, whereby Nekota provides transportation service to NEC. By separate contract effective on the same date, NPS entered into a transportation services agreement with NEC. The rates in the two agreements are the same. The contracts are for an initial term of ten years but only the contract between Nekota and NEC is renewable by mutual agreement for an additional ten years.

NPS' entitlement represents 62.5% of the capacity of Nekota's pipeline. For this it pays $48,000 per month, or $576,000 per year all of which is assigned to South Dakota gas operations.

Q. Is this a reasonable charge?

A. No. It greatly exceeds the affiliate Nekota's cost of providing the service. Nekota's investment in the pipeline is $1,185,000. For such an investment, an annual rental of $576,000 is excessive on its face. But combining this with the facts (i) that the facility has an expected life of at least 20 years (ii) that only 62.5 percent of the capacity of the line is committed to NPS and (iii) that, by separate agreement, NPS is obligated during the first five years of its contract to pay all inspection costs and operation and maintenance expenses, makes it abundantly clear that the charge is excessive, unreasonable and unjustified.

Moreover, while the contract requires payments from NPS are more than sufficient to pay for the entire line, the contract leaves 37.5% of the capacity uncommitted and available to NEC, the company's energy marketing affiliate for generating additional profits. Also, the fact that NEC's contract with Nekota is renewable for an additional ten years, while NPS contract with NEC is not, leaves open the possibility that, after the 10-year term of its contract, NPS will not be able to use the Nekota pipeline at all -- or at a reasonable cost -- if the market for gas transportation provides more lucrative opportunities for NEC.

Q. How did you develop the adjustment that you are recommending?

A. I have developed on page 1 of Exhibit___(DAJ-1) a levelized cost of service for the Nekota pipeline based on its actual original cost of $1,185,000. The levelized charge would compensate Nekota for return and income taxes and would recover the initial investment over twenty years. Typically, a full cost of service requires the addition of property taxes, which I have added, and operation and maintenance expenses. I have not included O&M costs because these expenses are being paid directly by NPS until December 31, 2001. The total cost of service amounts to $172,815, all of which I have assigned to NPS even though only 62.5% of the capacity is committed to it. This cost is

$403,186 less than the $576,000 currently being recovered by NPS through the PGA on an annual basis.

The PGA should be reduced by this amount ($403,186) and future PGA determinations should reflect the levelized fixed charge of $149,489, actual property taxes and, when Nekota begins to incur them, O&M expenses.

Q. Why do you assign the entire Nekota pipeline cost of service to NPS when Nekota and NEC have not committed the entire capacity of the line to NPS?

A. Formal contracts notwithstanding, the company has represented that the entire capacity of the line will be available to NPS when it is needed and that, even now, NPS is permitted to use capacity in excess of 15,000MMBtu/day. Meanwhile, any capacity unused by NPS is available to NEC for sales to others.

Q. Why are you recommending that the company be required to refund amounts collected since December, 1996?

A. The charges imposed on NPS by its affiliate are grossly excessive and have been so since they were first flowed through the PGA in December, 1996. This has resulted in substantial overcharges to NPS' gas customers in South Dakota. Moreover, the effects of this less-than-arm's length transaction were introduced into NPS' PGA calculations without special notice by the company and continue to be identified in those filings, without reference to Nekota Resources or Northwestern Energy but as "NBPL-ABERDEEN CAPACITY".

Use of the semi-automatic pass-through mechanism in this manner is not appropriate in my opinion and an order requiring refunds, with interest, is justified. Since the collections will have taken place over a period of nearly three years, I recommend that the principal amount of the overcharges, together with accrued interest, be flowed back to ratepayers over a three year period in the PGA.

RECEIVED

OCT 19 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STATE OF SOUTH DAKOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the Matter of the Application of NorthWestern Public Service For Authority to Increase Natural Gas Rates in South Dakota	))))	Docket No. NG99-002

EXHIBIT
7
10-20-99 LG

SETTLEMENT AGREEMENT BETWEEN NORTHWESTERN PUBLIC SERVICE AND COMMISSION STAFF

This Settlement Agreement is made and entered into by and between NorthWestern Public Service (the "Company"), a division of NorthWestern Corporation, and the Staff of the South Dakota Public Utilities Commission ("Staff").

I.

BACKGROUND

On June 1, 1999, the Company filed an application with the Public Utilities Commission ("Commission") for an increase in South Dakota revenue to the Company of $2,108,112 or approximately 6% based on the test year ending December 31, 1998, as adjusted. The Company cited increased costs of operation and its expanded distribution system since its last general rate increase, filed in 1994, as the reasons for the proposed change in rates.

On June 25, 1999, the Commission filed a notice of opportunity to intervene. No petitions to intervene have been received by the Commission.

The Staff submitted numerous data requests to the Company during the course of the Staff investigation. On September 24, 1999, Commission Staff filed the testimony of Robert G. Towers, David Jacobson, Martin C. Bettmann, Michele M. Farris, Keith A. Senger and Basil L. Copeland, Jr.. Commission Staff recommended an increase in Company revenue of $402,290 which reflected a disallowance related to the Nekota pipeline. During and following the receipt of the data responses from the Company, the Staff and the Company engaged in numerous discussions relating to the settlement of a variety of issues. The procedural schedule related to the Company's time to file rebuttal testimony was

suspended by the Commission based upon the representations by the Company and the Staff that a substantial agreement concerning the settlement of the proceeding had been reached.

II.

ELEMENTS OF THE SETTLEMENT AGREEMENT

Article I. Revenue Requirement

The Company and the Staff agree that, if the Commission approves this Settlement Agreement ("Agreement"), the Company will file revised rate schedules to produce an annual increase in base rate revenue levels (i.e., excluding purchased gas cost adjustment and sales taxes) of $1,279,025 applicable to retail natural gas service. The revised rate schedules shall be effective for billings rendered on and after December 1, 1999, provided there is Commission approval of this Agreement and the revised rate schedules.

Article II. Rate Design

The agreed to change in rates would affect customer classes by the following percentages:

Class	% Increase
Residential – Rate 81	3.8
Small Commercial – Rate 82	3.9
Large Commercial/Industrial Firm Rate 84 (Option A)	1.6
Large Commercial/Industrial Rate 84 (Option B)	1.5
Large Commercial/Industrial Interruptible – Rate 85 (Option A)	1.8
Large Commercial/Industrial Interruptible – Rate 85 (Option B)	1.4
Transportation – Rate 87 (Option A)	22.5
Transportation – Rate 87 (Option B)	9.1
Contracts with Deviations	1.5
Total South Dakota	3.8

Article III. Other Conditions

The parties agree to a return on common equity of 10.25% and that Company's capital structure shall be based on its stand alone capital structure rather than a consolidated capital structure.

It is further agreed by the parties that the Nekota pipeline issue which was raised by Commission Staff has been eliminated from the base rate determination, and alternatively will be heard as a Purchase Gas Adjustment request before the Public Utilities Commission on October 20, and October 21, 1999 as a separate proceeding from the base rate determination.

It is further agreed by the parties that the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, contracts between the Company and any separate affiliated company that does business with the Company, related to the Company's utility business in South Dakota. Such contracts will identify the products and services to be provided by the affiliate to the Company and will provide that the pricing of such products and services shall be based upon the affiliate's costs, which costs include a reasonable profit for the affiliate. The Company will maintain and, upon Commission or Commission Staff request, furnish information supporting the basis of the pricing of such products and services, whether based on costs of labor and materials provided or specific allocations of joint or common costs. In addition, the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, an explanation of NorthWestern Corporation expenses or allocations charged to the Company. Thereafter, June 30th of each year (beginning June 30, 2000), the Company will file with the Commission any new or revised contracts with each affiliate doing business with the Company and a statement of all transactions between the Company and each affiliate during the preceding calendar year, as well as any changes in the methodology for the charging of any NorthWestern Corporation expenses or allocations to the Company.

Article IV General Conditions

1. It is agreed that this Agreement is a negotiated dollar settlement and establishes no principles or precedent and shall not be deemed to foreclose the Company or the Staff or any other person from making any contention in any proceeding or investigation, including the right of the Staff or any other interested person to seek a rate change if justified on any basis.

2. Approval of this Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this proceeding.

3. The Agreement is expressly conditioned upon the Commission's acceptance of all the provisions thereof, without change or condition which is unacceptable to any party.

4. Discussions between the Company and the Staff which produced this Agreement have been conducted with the customary understanding that all offers of settlement and discussions relating thereto are privileged and shall not be used in any manner in connection with this proceeding or otherwise, except as required by law.

5. This Agreement includes all terms of Settlement and is submitted on the condition that in the event the Commission imposes any change in or condition to this Agreement which is unacceptable to any party, this Agreement shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding or be used for any other purpose.

6. This Agreement shall be binding upon the parties hereto, and upon their successors, assigns, agents and representatives.

7. It is understood that the Staff enters into this Agreement for the benefit of the Company's South Dakota natural gas customers affected hereby.

8. This Agreement is entered into by and between the Company and the Staff by their respective agents who represent that they are fully authorized to do so on behalf of their principals.

Staff of the South Dakota
Public Utilities Commission

By Karen E. Cremer
Title Staff Attorney
Dated: October 19, 1999

NorthWestern Public Service
a division of NorthWestern Corporation

By _____
Title President & CEO
Dated October 19, 1999

Attached to this Settlement Agreement and incorporated herein are the attached schedules

Northwestern Public Service
South Dakota - Gas
Revenue Increase
Per Staff

Line No.	RATE STEP	THERMS (A)	THERMS (B)	TOTAL MARGIN (C) Test Year Revenue	REVISED (D) Proposed Revenue	INCREASE (F) Revenue (Inc./Dec.)	PERCENT INCREASE (G) Percent (Inc./Dec.)
	REVENUE INCREASE by RATE CODE						
1	RATE 81	33,197,790	33,197,790	20,189,402	20,961,369	771,967	3.8%
2	RATE 82	15,866,880	15,866,880	8,226,248	8,546,645	320,397	3.9%
3	RATE 84 (OPTION A&B)	5,936,020	5,936,020	2,235,630	2,269,986	34,356	1.5%
4	RATE 85 (OPTION A&B)	4,425,500	4,425,500	1,431,062	1,455,934	24,871	1.7%
5	RATE 87 (OPTION A&B)	29,121,130	29,121,130	1,211,082	1,334,781	123,699	10.2%
6	COMBINED RATE 84, 85, and 87 Sum of Line 3, 4, and 5	39,482,650	39,482,650	4,877,775	5,060,701	182,926	3.8%
7	CONTRACTS with DEVIATIONS	10,400,310	10,400,310	196,440	199,376	2,936	1.5%
8	TOTAL (Sum of Lines 1, 2, 6, and 7)	98,947,630	98,947,630	$ 33,489,365	$ 34,768,090	$ 1,278,226	3.8%

Northwestern Public Service
South Dakota - Gas
Residential - Rate 81 and Small Commercial - Rate 82
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Residential - Rate Code 81**									
2										
3		ALL THERMS CURRENTLY (FIRST 30)	Therms	9,414,430	9,414,430	0.2000	0.2055	1,882,886	1,934,665	51,779
4		EXCESS	Therms	23,783,360	23,783,360	0.1220	0.1270	2,901,570	3,020,487	118,917
5										
6		CUSTOMER CHARGE	BILL	400,847	400,847	4.50	6.00	1,803,812	2,405,082	601,271
7										
8		AD VALOREM TAX ADJUSTMENT		33,197,790	33,197,790	0.0156	0.0156	517,886	517,886	0
9		MGP REMOVAL COST ADJUSTMENT		33,197,790	33,197,790	0.0140	0.0140	464,769	464,769	0
10		GAS COST COMMODITY CHARGE		33,197,790	33,197,790	0.2043	0.2043	6,782,308	6,782,308	0
11		GAS COST DEMAND CHARGE		33,197,790	33,197,790	0.1758	0.1758	5,836,171	5,836,171	0
12										
13		TOTAL		33,197,790	33,197,790			20,189,402	20,961,369	771,967
								6,588,267		
14	**Small Commercial - Rate Code 82**									
15										
16		ALL THERMS CURRENTLY (FIRST 400)	Therms	8,490,570	8,490,570	0.1141	0.1309	968,774	1,111,416	142,642
17		NEXT 1,600	Therms	6,108,520	6,108,520	0.0841	0.0891	513,558	544,091	30,533
18		EXCESS	Therms	1,269,790	1,269,790	0.0541	0.0541	68,696	68,696	0
19										
20		CUSTOMER CHARGE	BILL	58,889	58,889	4.50	7.00	265,001	412,223	147,223
21										
22		AD VALOREM TAX ADJUSTMENT		15,866,880	15,866,880	0.0099	0.0099	157,082	157,082	0
23		MGP REMOVAL COST ADJUSTMENT		15,866,880	15,866,880	0.0140	0.0140	222,136	222,136	0
24		GAS COST COMMODITY CHARGE		15,866,880	15,866,880	0.2043	0.2043	3,241,604	3,241,604	0
25		GAS COST DEMAND CHARGE		15,866,880	15,866,880	0.1758	0.1758	2,789,398	2,789,398	0
26										
27		TOTAL		15,866,880	15,866,880			8,226,248	8,546,645	320,397

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Firm - Rate 84 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Large Commercial/Industrial Firm - Rate Code 84 (Option A)**									
2										
3		ALL THERMS	Therms	5,505,570	5,505,570	0.0364	0.0388	200,403	213,616	13,213
4										
5		CUSTOMER CHARGE	BILL	1,963	1,963	70.00	80.00	137,410	157,040	19,630
6										
7		AD VALOREM TAX ADJUSTMENT		5,505,570	5,505,570	0.0064	0.0064	35,236	35,236	0
8		MGP REMOVAL COST ADJUSTMENT		5,505,570	5,505,570	0.0140	0.0140	77,078	77,078	0
9		GAS COST COMMODITY CHARGE		5,505,570	5,505,570	0.2300	0.2300	1,266,281	1,266,281	0
10		GAS COST DEMAND CHARGE		425,480	425,480	0.8700	0.8700	370,168	370,168	0
11		RELEASE CAPACITY/BALANCING SURCHARGE		680,040	680,040	0.0170	0.0170	11,561	11,561	0
12		SUBTOTAL		5,505,570	5,505,570			2,098,136	2,130,979	32,843
13	**Large Commercial/Industrial Firm - Rate Code 84 (Option B)**									
14										
15		ALL THERMS	Therms	430,450	430,450	0.0180	0.0204	7,748	8,781	1,033
16										
17		CUSTOMER CHARGE	BILL	24	24	260.00	280.00	6,240	6,720	480
18										
19		AD VALOREM TAX ADJUSTMENT		430,450	430,450	0.0042	0.0042	1,808	1,808	0
20		MGP REMOVAL COST ADJUSTMENT		430,450	430,450	0.0140	0.0140	6,026	6,026	0
21		GAS COST COMMODITY CHARGE		430,450	430,450	0.2300	0.2300	99,004	99,004	0
22		GAS COST DEMAND CHARGE		18,120	18,120	0.8700	0.8700	15,764	15,764	0
23		RELEASE CAPACITY/BALANCING SURCHARGE		53,180	53,180	0.0170	0.0170	904	904	0
		SUBTOTAL		430,450	430,450			137,494	139,007	1,513
24										
25		TOTAL		5,936,020	5,936,020			$2,235,630	$2,269,986	$34,356

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial									
1	**Interruptible - Rate Code 85 (Option A)**									
2										
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451
4										
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290
6										
7		AD VALOREM TAX ADJUSTMENT		3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0
8		MGP REMOVAL COST ADJUSTMENT		3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0
9		GAS COST COMMODITY CHARGE		3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0
10		RELEASE CAPACITY/BALANCING SURCHARGE		3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741
	Large Commercial/Industrial									
12	**Interruptible - Rate Code 85 (Option B)**									
13										
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171
15										
16		CUSTOMER CHARGE	BILL	48	48	260.00	260.00	12,480	13,440	960
17										
18		AD VALOREM TAX ADJUSTMENT		487,770	487,770	0.0042	0.0042	2,049	2,049	0
19		MGP REMOVAL COST ADJUSTMENT		487,770	487,770	0.0140	0.0140	6,829	6,829	0
20		GAS COST COMMODITY CHARGE		487,770	487,770	0.2300	0.2300	112,187	112,187	0
21		RELEASE CAPACITY/BALANCING SURCHARGE		487,770	487,770	0.0170	0.0170	8,292	8,292	0
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131
23										
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	Transportation - Rate Code 87 (Option A)									
2										
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191
4										
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720
6										
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0
10		SUBTOTAL		1,329,490	1,329,490			97,355	119,266	21,911
11	Transportation - Rate Code 87 (Option B)									
12										
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	566,949	66,700
14										
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320
16										
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0
20		SUBTOTAL		27,791,640	27,791,640			1,113,727	1,215,515	101,788
21										
22		TOTAL		29,121,130	29,121,130			1,211,082	1,334,781	123,699

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Contracts with Deviations**									
2										
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320
4										
5		CUSTOMER CHARGE	BILL	36	36	280.00	330.00	9,360	11,880	2,520
6										
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)
10										
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$4.50	$6.00
2	FIRST 30 THERMS	$0.20000	$0.20550
3	EXCESS THERMS	$0.12200	$0.12700
4	PGA and OTHER ADJ.	$0.40970	$0.40970

Residential - Rate Code 81

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$4.50	$6.00	$1.50	33.33%
6	10	10.60	12.15	1.56	14.67%
7	25	19.74	21.38	1.64	8.29%
8	50	33.43	35.19	1.77	5.28%
9	75	46.72	48.61	1.89	4.05%
10	80	49.38	51.29	1.92	3.88%
11	100	60.01	62.03	2.02	3.36%
12	125	73.30	75.44	2.14	2.92%
13	150	86.60	88.86	2.27	2.62%
14	175	99.89	102.28	2.39	2.39%
15	200	113.18	115.70	2.52	2.22%
16	225	126.47	129.11	2.64	2.09%
17	250	139.77	142.53	2.77	1.98%
18	300	166.35	169.37	3.02	1.81%
19	400	219.52	223.04	3.52	1.60%
20	500	272.69	276.71	4.01	1.47%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	196	$110.80	$113.29	$2.49	2.2%
FEB	168	$95.22	$97.57	$2.35	2.5%
MAR	148	$85.71	$87.97	$2.26	2.6%
APR	126	$73.80	$75.95	$2.14	2.9%
MAY	49	$32.65	$34.40	$1.76	5.4%
JUN	23	$18.81	$20.44	$1.63	8.7%
JUL	18	$15.77	$17.37	$1.60	10.2%
AUG	15	$13.58	$15.17	$1.58	11.6%
SEP	14	$13.27	$14.85	$1.58	11.9%
OCT	32	$23.76	$25.43	$1.67	7.0%
NOV	82	$50.27	$52.19	$1.92	3.8%
DEC	118	$69.77	$71.88	$2.11	3.0%
TOTAL	988	$603.41	$626.51	$23.09	3.8%

AVERAGE MONTHLY USE = 82 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$4.50	$7.00
22	FIRST 400 THERMS	$0.11410	$0.13090
23	NEXT 1,600 THERMS	$0.08410	$0.08910
24	EXCESS THERMS	$0.05410	$0.05410
25	PGA and OTHER ADJ.	$0.40970	$0.40970

SMALL COMMERCIAL - Rate Code 82

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
26	0	4.50	7.00	$2.50	55.56%
27	50	30.69	34.03	3.34	10.88%
28	100	56.88	61.06	4.18	7.35%
29	200	109.28	115.12	5.86	5.36%
30	350	187.83	196.21	8.38	4.46%
31	500	263.40	273.12	9.72	3.69%
32	750	386.85	397.82	10.97	2.84%
33	1000	510.30	522.52	12.22	2.39%
34	1500	757.20	771.92	14.72	1.94%
35	2000	1,004.10	1,021.32	17.22	1.71%
36	2500	1,238.00	1,253.22	17.22	1.39%
37	3,000	1,467.90	1,485.12	17.22	1.17%
38					
39					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	621	316.57	325.79	9.22	2.9%
FEB	577	296.21	305.43	9.22	3.1%
MAR	503	261.61	270.83	9.22	3.5%
APR	397	212.54	221.71	9.17	4.3%
MAY	138	76.60	81.42	4.81	6.3%
JUN	68	40.28	43.93	3.65	9.1%
JUL	60	35.92	39.43	3.51	9.8%
AUG	54	32.83	36.24	3.41	10.4%
SEP	50	30.92	34.27	3.35	10.8%
OCT	90	51.90	55.92	4.02	7.7%
NOV	251	141.25	148.13	6.89	4.9%
DEC	394	210.73	219.85	9.11	4.3%
TOTAL	3,214	$1,707	$1,783	$75.58	4.4%

AVERAGE MONTHLY USE = 268 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
38	CUSTOMER CHARGE	$70.00	$80.00
39	ALL THERMS	$0.03640	$0.03880
40	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION A)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
41	0	70.00	80.00	$10.00	14.29%
42	250	141.70	152.30	10.60	7.48%
43	500	213.40	224.60	11.20	5.25%
44	750	285.10	296.90	11.80	4.14%
45	1,000	356.80	369.20	12.40	3.48%
46	1,500	500.20	513.80	13.60	2.72%
47	2,000	643.60	658.40	14.80	2.30%
48	3,000	930.40	947.60	17.20	1.85%
49	4,000	1,217.20	1,236.80	19.60	1.61%
50	5,000	1,504.00	1,526.00	22.00	1.46%
51	6,000	1,790.80	1,815.20	24.40	1.36%
52	7,000	2,077.60	2,104.40	26.80	1.29%
53	8,000	2,364.40	2,393.60	29.20	1.23%
54					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	6,298	1,676.18	1,801.29	25.11	1.3%
FEB	5,230	1,569.94	1,592.49	22.55	1.4%
MAR	4,715	1,422.15	1,443.46	21.32	1.5%
APR	4,008	1,219.43	1,239.04	19.62	1.6%
MAY	2,138	683.28	698.41	15.13	2.2%
JUN	392	182.53	193.47	10.94	6.0%
JUL	1,376	464.76	478.07	13.30	2.9%
AUG	737	281.46	293.23	11.77	4.2%
SEP	658	258.59	270.17	11.58	4.5%
OCT	1,287	439.09	452.18	13.09	3.0%
NOV	2,808	875.33	892.07	16.74	1.9%
DEC	3,471	1,065.37	1,083.70	18.33	1.7%
TOTAL	33,118	$10,338	$10,538	$199.48	1.9%

AVERAGE MONTHLY USE = 2,760 Therms

LINE NO.		PRESENT	PROPOSED
55	CUSTOMER CHARGE	$260.00	$280.00
56	ALL THERMS	$0.01800	$0.02040
57	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION B)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
58	0	260.00	280.00	$20.00	7.69%
59	250	327.10	347.70	20.60	6.30%
60	500	394.20	415.40	21.20	5.38%
61	1,000	528.40	550.80	22.40	4.24%
62	2,500	931.00	957.00	26.00	2.79%
63	5,000	1,602.00	1,634.00	32.00	2.00%
64	10,000	2,944.00	2,988.00	44.00	1.49%
65	20,000	5,628.00	5,696.00	68.00	1.21%
66	35,000	9,654.00	9,758.00	104.00	1.08%
67	50,000	13,680.00	13,820.00	140.00	1.02%
68	60,000	16,364.00	16,528.00	164.00	1.00%
69	70,000	19,048.00	19,236.00	188.00	0.99%
70	75,000	20,390.00	20,590.00	200.00	0.98%
71					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	70,064	19,065.09	19,253.24	188.15	1.0%
FEB	32,177	8,896.28	8,993.51	97.22	1.1%
MAR	28,048	7,787.98	7,875.29	87.31	1.1%
APR	19,295	5,438.85	5,505.16	66.31	1.2%
MAY	12,867	3,713.40	3,764.28	50.88	1.4%
JUN	5,147	1,641.43	1,673.79	32.35	2.0%
JUL	1,253	596.44	619.45	23.01	3.9%
AUG	377	361.19	382.09	20.90	5.8%
SEP	811	477.67	499.62	21.95	4.6%
OCT	3,412	1,175.79	1,203.98	28.19	2.4%
NOV	10,386	3,047.62	3,092.35	44.93	1.5%
DEC	31,388	8,684.51	8,779.84	95.33	1.1%
TOTAL	215,224	$60,888	$61,643	$756.54	1.2%

AVERAGE MONTHLY USE = 17,935 Therms

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
	Large Commercial/Industrial										
1	Interruptible - Rate Code 85 (Option A)										
2											
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451	
4											
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290	
6											
7	AD VALOREM TAX ADJUSTMENT			3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0	
8	MGP REMOVAL COST ADJUSTMENT			3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0	
9	GAS COST COMMODITY CHARGE			3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0	
10	RELEASE CAPACITY/BALANCING SURCHARGE			3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0	
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741	1.8%
	Large Commercial/Industrial										
12	Interruptible - Rate Code 85 (Option B)										
13											
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171	
15											
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960	
17											
18	AD VALOREM TAX ADJUSTMENT			487,770	487,770	0.0042	0.0042	2,049	2,049	0	
19	MGP REMOVAL COST ADJUSTMENT			487,770	487,770	0.0140	0.0140	6,829	6,829	0	
20	GAS COST COMMODITY CHARGE			487,770	487,770	0.2300	0.2300	112,187	112,187	0	
21	RELEASE CAPACITY/BALANCING SURCHARGE			487,770	487,770	0.0170	0.0170	8,292	8,292	0	
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131	1.4%
23											
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871	1.7%

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	Transportation - Rate Code 87 (Option A)										
2											
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191	
4											
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720	
6											
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0	
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0084	8,509	8,509	0	
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0	
10		SUBTOTAL		1,329,490	1,329,490			97,355	119,266	21,911	22.5%
11	Transportation - Rate Code 87 (Option B)										
12											
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	568,949	68,700	
14											
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320	
16											
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)	
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0	
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0	
20		SUBTOTAL		27,791,640	27,791,640			1,113,727	1,215,515	101,788	9.1%
21											
22		TOTAL		29,121,130	29,121,130			1,211,082	1,334,781	123,699	10.2%

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	Contracts with Deviations										
2											
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320	
4											
5		CUSTOMER CHARGE	BILL	36	36	260.00	330.00	9,360	11,880	2,520	
6											
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0	
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0	
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)	
10											
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936	1.5%

THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

RECEIVED
OCT 27 1999
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	NG99-002 TRANSCRIPT OF SETTLEMENT

HEARD BEFORE THE PUBLIC UTILITIES COMMISSION

PROCEEDINGS: October 20, 1999
9:00 A.M.
Room 413, Capitol Building
Pierre, South Dakota

PUC COMMISSION: Jim Burg, Chairman
Laska Schoenfelder, Commissioner
Pam Nelson, Commissioner

COMMISSION STAFF PRESENT: Rolayne Ailts Wiest
Karen Cremer
Gregory A. Rislov
David Jacobson
Martin Bettmann

Reported by: Lori J. Grode, RMR

ORIGINAL

APPEARANCES

For NWPS: Mr. Russell C. Molstad, Jr.
600 Market Street West
Huron, South Dakota, 57350

and

Mr. Alan D. Dietrich
125 S. Dakota Ave., #1100
Sioux Falls, South Dakota, 57104

EXHIBITS

No. 7	Northwestern Public Service Settlement Agreement with Commission Staff

P R O C E E D I N G S

CHAIRMAN BURG: Bob, can you hear me?

MR. TOWERS: Yes, I can.

CHAIRMAN BURG: Welcome. I'll begin the hearing for Docket NG99-002, In the Matter of the Application of Northwestern Public Service for Authority to Increase Rates for Natural Gas Service.

The time is approximately 9:00 a.m. The date is October 20, 1999, and the location of the hearing is Room 413, State Capitol Building, Pierre, South Dakota.

I am Jim Burg, Commission Chairman. Commissioners Laska Schoenfelder and Pam Nelson are also present. I am presiding over this hearing. The hearing was noticed pursuant to the Commission's Order for Notice of Hearing issued August 3rd, 1999, and the Amended Order for the Notice of Hearing issued October 12, 1999.

The issue at this hearing is whether the Commission shall grant Northwestern Public Service's request to implement revised natural gas rates, schedules, designed to produce additional revenues of $2,108,112.

All parties have the right to be present and to be represented by an attorney. All persons so

testifying will be sworn in and subject to cross-examination by the parties. The Commission's final decision may be appealed by the parties to the State Circuit Court and the State Supreme Court.

Rolayne Wiest will act as Commission counsel. She may provide recommended rulings on procedural and evidentiary matters. The Commission may overrule its counsel's preliminary rulings throughout the hearing. If not overruled, the preliminary rulings will become final rulings.

At this time I'll take appearances for the parties. Northwestern Public Service.

MR. MOLSTAD: Yes, Mr. Chairman. Appearing for Northwestern Public is myself, Russell C. Molstad, Jr., Rusty Molstad, and Alan Dietrich.

CHAIRMAN BURG: Staff.

MS. CREMER: Karen Cremer for staff.

CHAIRMAN BURG: And let the record show that Bob Towers is on the phone. And he's an expert witness for staff; is that correct?

MS. CREMER: Yes. He will be explaining the settlement position of staff.

CHAIRMAN BURG: Okay. And he is joining us on the phone?

MR. TOWERS: Yes, I am here.

CHAIRMAN BURG: Good morning. With that, I'll turn it over to the parties at this time for what I understand is a settlement proposal; is that correct?

MR. MOLSTAD: That's correct, Mr. Chairman. Can you hear me, Bob?

MR. TOWERS: Yes, I can perfectly.

CHAIRMAN BURG: Wonderful.

MR. MOLSTAD: Before I start my presentation, Mr. Chairman, members of the Commission and Commission staff, I would like to introduce those that are here on behalf of Northwestern Public Service to answer any questions that you might have as this settlement agreement is discussed.

Here today are is Mike Hanson, also Rod Leyendecker, Jeff Decker, Curt Pohl, Dave Monahan, and Tom Hitchcock.

Northwestern Public Service filed for a revenue increase for its natural gas in South Dakota on June 1st. And in that particular request Northwestern asked for an annual revenue increase of approximately 2.1 million dollars, which would have been a six percent increase. This was the first natural gas revenue increase request since 1994.

Several reasons for this rate increase

request were increased costs of operation, and also recovery costs for the expanded distribution system.

In the course of the process itself and the rate increase application, the case was thoroughly reviewed by the staff. Data requests were exchanged, submitted, and exchanged by the parties, and so the case was thoroughly gone over.

At the conclusion of that portion the review of the staff and staff testimony was filed supporting an increase of approximately $402,000, compared to the 2.1 million dollars revenue increase that was requested by the company.

After the staff position was filed, staff and Northwestern entered into several settlement discussions which resulted in the settlement agreement that has been presented today for your consideration.

If you approve this settlement, you will be approving an annual overall revenue increase of approximately $1,279,000, which is approximately 3.8 percent compared to the six percent increase that was requested by Northwestern in its rate filing.

Northwestern is requesting that the new rates go into effect on December 1st of this year and that billings before December 1st will show the old rates and billings after December 1st will incorporate the

new rates for those billings.

I want to bring out just a couple items I know is of interest in this case. One is the issue in the settlement agreement dealing with affiliate contracts and just giving an overview of that.

As part of this settlement agreement Northwestern has agreed to provide to the Commission for its information by December 1st of this year contracts between Northwestern and any separate affiliated company that does business with Northwestern Public Service related to the utilities business in South Dakota.

These contracts will identify the parts and services to be provided by that affiliate company to Northwestern and also will provide that the pricing and products will be based on the affiliate's costs, which do include a reasonable profit.

We will maintain records and furnish information supporting the basis of the pricing of those services. Also, we will provide the Commission no later than December 1st an explanation of Northwestern's corporate expenses and allocations charged to Northwestern Public Service. In other words, the allocation of the cost from Northwestern Corporation to Northwestern Public Service.

And then after that, after June 30th, we will provide the Commission with any new and revised contracts and changes in methodology that has come about since the initial following. Also we would be including any changes of allocation of expenses from Northwestern Corporation to Northwestern Public Service.

The other issue that I want to bring to the Commission's attention in that part of the settlement agreement is the issue of the Nekota pipeline. The costs that have been charged from Northwestern Energy Corporation, which is a separate corporation to Northwestern Public Service, those have been agreed to be dealt with in the separate hearing that will follow this settlement hearing today as a separate proceeding, separate and apart from this rate case itself, to determine the reasonableness on a continuing basis of those costs that are being charged Northwestern Public Service connected to the Aberdeen pipeline.

We would ask you to approve this settlement in its entirety. We have brought several individuals here from Northwestern to answer any questions that you might have in this matter. And with that, we would entertain questions, Mr. Chairman.

CHAIRMAN BURG: Okay. Does staff have any

comments on the proposed settlement?

MS. CREMER: I thought we would go, if you want to ask the company questions, and then we would go after that, or we can go. Bob can give his --

CHAIRMAN BURG: My thinking is any comment you have may satisfy questions, and rather than duplicate them so -- because it was a settlement of both sides.

MS. CREMER: All right. Were you going to introduce the settlement agreement? I can.

MR. MOLSTAD: Yeah. I assume that you have it; right?

MS. CREMER: The original is in the Commission docket, yeah. Did you bring another?

MR. DIETRICH: We have a photocopy.

MR. MOLSTAD: We have a photocopy.

MS. CREMER: They all have a copy of it, but we should probably get it marked and placed in the record.

MR. MOLSTAD: Assuming you have the original to be marked.

MS. CREMER: It's in the docket downstairs.

CHAIRMAN BURG: We'll have to give the original copy to the reporter.

MR. MOLSTAD: Do we want to attach the --

MS. CREMER: Staff would join in the motion seeking approval of the settlement agreement.

Bob Towers, as we said, is on the line and will explain the settlement agreement from the staff's point of view. All the testimony was filed in this case up through the rebuttal of Tom Hitchcock and Mr. Hanson.

After Bob explains staff's position on this, the staff is available if you would have any questions. So, Bob, I would turn it over to you at this time.

MR. TOWERS: Okay. Fine. I'll try not to repeat too much of what Alan (sic) just already said.

We all know this case concerned a petition by the company for a 2.1 million dollar rate increase based on the 1998 test year. And as Alan (sic) indicated, if it's approved, if it were to have been approved, that would have been about a 6.26 percent increase in customer bills.

I prefer to look at the increase in terms of its impact on the non-gas portion of customer bills. Since gas costs are not an issue in a base rate case so the 2.1 million really would have been about a 17.8 percent increase in the relevant component of the customer's bill.

As Mr. Dietrich (sic) said, the company did cite increased costs since the 1994 rate adjustment and service area expansion costs that were being rolled into the rate determination at this time. The company designed the rates, or calculated the revenue requirement first to introduce a 9.27 overall return on rate base, which reflected an 11 1/4 percent return on equity capital.

And it designed rates by customer class to produce the same rates of return, each class producing the same overall rate of return. Most of the proposed rate increase, or a great portion of it, was reflected in significant increases in the proposed customer charges.

The staff took the company's filing, the testimony of each of its supporting data, analyzed them pretty thoroughly, engaged in fairly extensive discovery. Several of the staff people from Pierre went up to Huron to explore various things at the company's offices.

And, of course, the experience of the in-house staff was quite helpful. Particularly, I recall Martin Bettmann's experience. I think the pipeline inspector having been out in the field, his information was very helpful in understanding things

like the expansion of the territories, customer load growth, and things like the Nekota pipeline issue, which I'll mention later.

The staff combined -- the staff, after completing all this analysis, the staff presented testimony of six witnesses, including myself and my associate, Basil Copeland, and the various people there on your staff in Pierre.

All of the recommendations of the witnesses were combined into a single exhibit, which I presented, and that indicated a revenue deficiency, or justified rate increase of what we thought around $400,000 as opposed to the 2.1 million the company was requesting.

However, it became apparent very close to the time staff was ready to file its case, that one of the issues that was raised was, in all likelihood, the purchased gas adjustment issue rather than a base rate issue.

And as indicated in my testimony, that if that issue, which is the Nekota pipeline, Aberdeen pipeline issue, were to be severed, that the overall rate increase, base rate increase that would be justified was about $817,000, inasmuch as the PGA issue would have reduced rates by 470, netting out to the 402 that's in the filed exhibit.

Staff did not take issue with the company's class costs allocation. They appeared to be sound, reasonable, and generally consistent with what staff has done in the past with the settlement of the MidAmerican case.

Staff also endorsed the uniform rate of return concept and did not dispute the proposed customer charges, although we did take issue with the costs that the company had identified in support of the customer charges.

I know this is sometimes an issue of particular concern to the Commission so I would just mention that this company's residential customer charge presently is $4.50 per month and they're proposing to increase that to $6.00. And as I say, the staff is agreeing with that change. But $6.00, according to the company, was justified because the company believed the customer costs for that class were in the range of $14.00.

I looked at that issue and my determination was that the customer costs for the residential class were more like eight dollars, which is significantly below the company's cost determination, but still well above even the proposed customer charge.

So it was staff's view that the customer

charges that the company was proposing were cost justified.

There's also been discussion already of the affiliate transaction issue. This, I believe, is the first case in which the staff had to deal with the effects of significant restructuring of Northwestern Public Service Company.

As you know, the NWPS, sometimes you refer to as NPS, is now trying to distinguish the different entities. The utility is a division of Northwest, is now a division of Northwestern Corporation and Northwestern Corporation and subsidiaries that perform functions that used to be performed within the utility itself.

And that gives rise to these affiliated less-than-arms-length transactions which we found -- staff found to be a problem in analyzing the company's costs. The case is unique in that while we had difficulty dealing with or understanding what specifically the costs of the services performed in the test year were, the costs were significantly, in most cases, significantly lower than they had been in the immediately preceding years.

And so staff was reasonably confident that the costs built into this rate determination are

reasonable, yet staff could also see that this would be a formidable problem in the future in making some assessment of an appropriate reasonable cost for the services performed by affiliates.

So an important part of our recommendation in this case in the filed testimony was the recommendation that the arrangements between affiliates be formalized into contracts which would specify not only the services being provided, but just how those services are to be priced, and would provide a means, some measure of effort, for example, time logs, invoices, that sort of thing, which would support these transactions.

So that in the future when staff is looking at either gas or electric revenue requirements for this company, that they'll have a sound basis to make judgments about the affiliate transactions which seem to me are very significant.

The difference between the company and the staff on the revenue requirements issue, putting aside affiliate transactions and putting aside the Aberdeen pipeline issue, there are about, I think, according to my count, 12 or 13 issues addressed by various staff witnesses, including such things as the sales adjustment, computer rent, or affiliates' use of some

office space in Huron, and adjustments to the rate base for gas inventories, adjustments meaning reductions in claimed dues and association dues and economic development expenses, adjustments to rate case expense, account capital, deletion of some of the costs of the company's compensation plan, reduction in income taxes related to the filing of a consolidated return by Northwestern Corporation.

And, of course, the issue that's always here in rate cases, a rate of return, which is to say capital structure, what the differences of capital structure should be and the return on equity capital.

Following the filing the staff made, Mr. Dietrich (sic) indicated there was one big meeting in Pierre, which I attended, and then there were numerous discussions, I know, taking place to see if some of these issues could be resolved by settlement.

And the bottom line of those discussions was an agreement, good and comprehensive agreement, I believe, which contained three elements. One is the base rate increase of $1,279,000, which is to say about 60 percent of the company's request. That translates to an increase of 3.8 percent overall in customers' bills, but more importantly, as I view it, it's an increase of about 10.8 percent in the non-gas cost

portion of customers' bills.

And I cite that number because I kind of compare that number with what's happened to inflation generally during this four-year period since the last gas rate base rate adjustment. The CPI over the four-year period has increased by about 12 percent. So the settlement base rate increase is somewhat less, modestly less than general inflation that has occurred over the four-year period.

The second element of the settlement agreement is to separate the Aberdeen or Nekota pipeline issue and to try that as a separate PGA issue, which is what it is. And I understand the Commission will be addressing that following the consideration of the settlement.

And then the third component could be the agreement, as Mr. Dietrich (sic) explained, to file the affiliate agreement.

The base rate increase, first of all, staff does strongly recommend adoption of the settlement. I think the base rate increase is reasonable. It reflects movement on staff's part from the 800 and some, $870,000 I think the number was, that we first thought was cost justified.

It reflects movement on two issues: One is

the consolidated facts issue, and that's a significant movement on that issue of some $220,000. That should be really -- it really should be viewed as almost a correction to the staff's file in the case. The data we had relied on -- that I had relied on in preparing that adjustment were not the data that I thought they were. And when the proper data were used, the adjustment was diminished significantly, and that added 221,000 to the revenue requirement.

The remaining movement from the staff's part dealt with capital structure and return on equity. And, here again, we think the movement is justified. Ultimately the settlement reflected use of what's referred to as the stand-alone NWPS capital structure, which consists of about 46 percent equity. Equity being, of course, the most expensive and is the component of capitalization that a component on which the return is not tax deductible.

The company had in its filed case asked for a consolidated Northwestern capital structure, which had about 49 percent equity in it. And the staff witness, Basil Copeland, used an adjusted capital structure, which was about 37 percent equity.

So the staff has moved to the intermediate figure of 46 percent on the return on equity. The

company had requested the same rate of return on equity that had been granted to them in 1994. That was 11 1/4 percent. The staff's evidence was for a maximum return on equity of 10 percent. The settlement, however, is at just a slightly higher rate of 10 1/4.

We think 10 1/4 is justified and movement on capital structure are justified for several reasons. We note that the settlement produces a pretax bond interest coverage of about 2.9 times, which we think is ample but not excessive. 10 1/4 percent on equity is less than what the company asked for, less than what they entered in 1994, and just 25 basis points above staff's recommendation here. The overall rate return is also down from the rate of return in the last case.

And last of all, but not least of all, is that the whole settlement on revenue requirement was against the background of establishing procedures for the staff that will greatly facilitate, I think, the staff and Commission's assessment of the rate application in the future and that is the filing of these agreements between the affiliates.

CHAIRMAN BURG: Okay.

MR. TOWERS: That's it. We recommend the settlement be adopted.

CHAIRMAN BURG: Okay. Thank you, Bob.

Karen, do you have anything else from any from any other staff people or yourself?

MS. CREMER: No, we don't.

CHAIRMAN BURG: Bob, I have one I want clarified a little bit more on the income tax calculation. If I understand, the adjustment that is recommended in the settlement is to give some benefits to the tax savings from the consolidated filing to give some of those benefits to the rate payers?

MR. TOWERS: That's correct.

CHAIRMAN BURG: Because the -- and the reason for that is because the rate payers have a higher risk because they would have to share if the taxes were higher on a consolidated basis.

MR. TOWERS: That's one of the things that I observed in my testimony, that there is an exposure on the part of anyone entering into a consolidated return to the total tax owed. That's one reason.

But the main reason for the adjustment, however, is that the consolidated tax is the tax actually paid by the corporate entity. There is no other tax being paid to the federal government other than the tax that is calculated on the consolidated return.

And so whenever there is significant -- and

generally you like to see consistent preavailability of the taxable losses of affiliates, offsetting the taxable income of others joining in the consolidated return.

It's my belief that the entities having the taxable income should be apportioned a portion kind of a pro rata share of the benefits of the tax losses of the other entities. Because it's only by reason of the taxable income of those companies having taxable income that the tax losses are of any significant value.

CHAIRMAN BURG: And then how do they calculate it originally? In other words, why did you have to make adjustment?

MR. TOWERS: The company's filing reflected a stand-alone basis as if Northwestern Public Service, which is, as I said, only a division of Northwestern Corporation, were a separate taxpayer.

CHAIRMAN BURG: Okay. So they were calculated on the basis of stand-alone even though they filed consolidated?

MR. TOWERS: Yes.

CHAIRMAN BURG: Okay. That clarifies it. Any other questions?

COMMISSIONER SCHOENFELDER: I have some. I think my question -- this is Commissioner Schoenfelder,

Mr. Towers. I think my question goes to the company basically. But I'm looking at -- well, obviously when anyone presents us with a customer charge increase, we expect a certain amount of dissatisfaction from your public.

I'm looking at the transportation rate 87 where you have Option A and Option B on the schedule with the settlement. I think for my clarification, I think if I've calculated this right, you have 26 customers on Option A?

MR. TOWERS: Miss Schoenfelder, if you're asking that of me --

COMMISSIONER SCHOENFELDER: I'm asking the company is who I'm asking, Mr. Towers. I think that's appropriate that I ask the company that. I think if I calculated it right, it should be --

MR. HITCHCOCK: I'm Mr. Hitchcock. Yes, and 26 customers would be correct.

COMMISSIONER SCHOENFELDER: Okay. Without asking specifically who those customers are, I guess I could ask you that, but what I really want to know is what kind of customers they are, or what is -- I can see what their consumption is. But I want to know what their size is. Is this sort of small business?

MR. HITCHCOCK: These are customers that

would generally be better off under this rate if they used less than 110,000 therms of gas in a year.

COMMISSIONER SCHOENFELDER: I understood that.

MR. HITCHCOCK: So they are the small customers. Principally, the customers that are transporting on Northwestern's system today that would fit this category would be school districts, some grade schools and some smaller industries.

COMMISSIONER SCHOENFELDER: Churches?

MR. TOWERS: We don't have any churches that are on the --

COMMISSIONER SCHOENFELDER: The reason I'm asking this is a significant increase in the customer service charge from 70 to $130, if I'm reading this chart right. And that seems to me that, you know, they might be better off there.

But if they don't like the up-front charge, the customer service charge there, is there another way that you can -- is there another proposal for them that might be more palatable to some of those entities?

MR. HITCHCOCK: I guess I could answer the question this way: If they were on our small Option A service for either rate 84 or rate 85, they're still going to incur that same customer charge increase. I'm

sorry, they're going to have an increase there, but it's going to be still $10.

What we're doing with the transport customers is each of them is going to have a $50.00 increase there to pay for the cost of additional telemetering expense because we have to basically balance these loads on a daily basis and track their units of consumption.

When they're a sales customer, those meters are just read once a month.

COMMISSIONER SCHOENFELDER: But the 70 to 130 is more than 50 bucks, it's 60, isn't it?

MR. HITCHCOCK: Yes, but we started with the premise that all those customers got a $10 general increase and those that were transporting would have an additional 50.

COMMISSIONER SCHOENFELDER: Okay. But there is another option if they wish, if they go to a sales -- to sales rather than to transportation tariffs.

MR. HITCHCOCK: Yes.

COMMISSIONER SCHOENFELDER: Okay. That just seems significant to me, as did Option B, but Option B you have a lot more customers there. I assume those are probably larger users?

MR. HITCHCOCK: I would characterize that the

Option B customers would -- most of them are of such size that they would rather see a bigger increase in a customer charge than the unit charge because some of these customers have such big volumes that even $100 change in a customer charge in a month is minimal compared to their volumetric charge.

COMMISSIONER SCHOENFELDER: I'm not going to disagree with this. I just wanted it explained a little more. And I think we also need to realize there's a little bit of rate shock in there.

MR. HITCHCOCK: Yes.

COMMISSIONER SCHOENFELDER: Thank you.

CHAIRMAN BURG: Just to follow the quick question on that one. Why was it necessary to make that increase in this one? I mean, in other words, was it out of balance in the past that made it necessary to make that kind of adjustment?

MR. HITCHCOCK: This goes to a proceeding we had about three years ago, and I think the docket was NG96-015 where PAM Natural Gas sent a memo, or an E-mail to the Commission expressing some concerns over the purchased gas costs of the company and certainly some other tariff issues that they had.

That led to a filing by the company during mid-year '96 where we looked at the services that were

provided. And generally the transportation customers and the sales customer, if they were the same class, that distribution service, plus customer charge was settled at the same rate. Essentially, if you were a transport customer you had the same delivery service costs that a sales customer had. The sales customer would just pay for the added sales or purchased gas cost of the company in the tariff.

Through the last three years of having transportation business on our system, there is certainly a lot of costs that go with transportation customers because you have to measure those costs on a daily basis, forward information to those third party shippers, there's a lot of phone charges, faxes, you know, administrative costs.

I guess the way I look at these rates there is a choice for customers. They can either stay sales customers or transport and if the economics are there, they should have the right to transport. But I think that those customers should pay a fair cost of providing that alternative service.

CHAIRMAN BURG: But my question was is when that was established. I mean why the necessary adjustment at this time to the degree it is in the class 87, which is incurred risk? Was that a

miscalculation at the time that the actual costs that went into it?

MR. HITCHCOCK: No. It was just part of the settlement of that proceeding to -- basically Jennifer Erickson was saying they should -- they have the same cost. Well, rather than trying to bring that out as an issue and have a different rate there, we just settled at that rate and said, you know, if we file another rate case in the future, we'll look at those costs. And that's what we've done here.

CHAIRMAN BURG: Do you have anything?

COMMISSIONER NELSON: How would a transport customer go to being a sales customer? What would be the difference in how he gets that service? I mean because I'm concerned that schools are one of the people that are going to be hard hit with this particular rate increase.

So how would they be able to -- what would they have to do to save as a sales customer? I don't understand the difference between transport customers and sales customers, I guess.

MR. HITCHCOCK: Okay. All the school would have to do is say to whoever their main shipper is, we don't want to transport anymore. We want to go back to the utility sales service because we've looked at the

economics of it and we're probably better off under a sales rate.

Now, some of those schools, the reason that they go to transportation service is that there are periods during the year in which it becomes economical for them to lock in their cost of gas supply for budget purposes.

If they were on the sales tariff, the gas supply component of the rate is just simply a market rate, so it is subject to extreme market fluctuations. But certainly a transport customer can go back to sales customer status.

COMMISSIONER NELSON: Does it have any hing to do with a firm price versus an interruptible price?

MR. HITCHCOCK: No.

COMMISSIONER NELSON: Try again to explain to me how you can -- what a transport customer, really how does he get his product versus the salesperson customer?

MR. HITCHCOCK: If you're under sales service with NPS, NPS handles all of the transactions and just bills a gas supply component on top of the base rate component, And that's a regulated rate. The PGA and the base rates are costs that are approved by the Commission.

If you're a transport customer, you have to go and find a party that will line up your gas supply and deliver it to the town border station. You pay those costs, plus the cost of that delivery on the distribution system or NPS system.

COMMISSIONER NELSON: That takes care of it. Thank you.

CHAIRMAN BURG: You said one of the advantages sometimes that they use is to lock in their gas price at a favorable time sometime through the season?

MR. HITCHCOCK: Yes.

CHAIRMAN BURG: Do you offer that service to sales customers if they want it?

MR. HITCHCOCK: No.

CHAIRMAN BURG: So, in other words, their costs are on a per month basis?

MR. HITCHCOCK: Yes.

CHAIRMAN BURG: One other thing I need and I don't know who's the best one to explain it. I thought I understood how we got from 2,108,112 to the recommended 402,290, then the settlement of $1,279,025. But I'm a little bit confused again and I'm also saying this settlement of the outstanding issue, where does that fit into these figures?

MR. HITCHCOCK: I'll try to address that. The two million one was of course what the company filed. The 400,000 was staff's testimony position in the case. After all of their adjustments, including the pipeline issue, the pipeline issue was $470,000 proposed adjustment.

Because we have determined that that's a purchased gas adjustment issue, that 470 is added to the 400,000 initial proposed increase to get to 870. The difference between 870 and 1,279,000 is the return on equity capital structure change, plus the consolidated tax saves changes. The combination of those two adjustments gets you from 870 to 1,279,000.

CHAIRMAN BURG: So the million, what was that again, 279, includes the PGA adjustment that is not yet determined?

MR. HITCHCOCK: It includes the -- it excludes the approximate PGA adjustment now because that's part of a separate proceeding. And so we're only looking at the base rates. But, you're correct, if that was still an issue, then we wouldn't have been at 1,279,000 in total, we would have been 470,000.

CHAIRMAN BURG: That's the part I wasn't quite clear on whether this included that or didn't include it. Even though that's not a totally done

deal, that's something that is disputed yet. And Greg just laid out for me a little bit better just exactly how we arrived at that, I guess.

And this probably is my lack of economic understanding, but the 221,905 consolidated tax savings, I'm not sure how I understand how that was an add-on. I would have thought it would have gone the other way.

MR. TOWERS: The remaining adjustment for consolidated tax savings is a negative thing. It simply was a larger negative before and it's been diminished.

CHAIRMAN BURG: But in the 400,000 the staff took the whole thing out?

MR. TOWERS: That's right. We had a very large adjustment for consolidated.

CHAIRMAN BURG: And you put 221 back in; is that correct?

MR. TOWERS: That's correct.

CHAIRMAN BURG: Now I understand.

COMMISSIONER NELSON: And the 221 that you put back in was because of the wrong numbers that you had plugged in in the formula in the beginning?

MR. TOWERS: That's right.

MR. HITCHCOCK: I want to make that clear

that the company itself did not propose a consolidated tax savings adjustment in our case.

CHAIRMAN BURG: Okay. Any other questions from anybody or anything to add?

MR. RISLOV: Either Tom or Martin could address this question. But, again, getting to transportation rate 87, Option A, I believe the -- if I'm correct, under the settlement, the overall increase for that category based on test year consumption will be 22 1/2 percent; is that correct.

MR. BETTMANN: Yes.

MR. RISLOV: Now, if I could go back to what Tom said and making sure I have this correct, did you say the average customer used 110,000 therms a year?

MR. HITCHCOCK: No. The average customer used less than that, but that was the break even amount to between an Option A and an Option B customer. If you have used more than that, you would be paying a lower cost under Option B.

MR. RISLOV: What does your average customer under Option A use, do you know?

MR. HITCHCOCK: In the proposed test year quantity, approximately 51,000 therms.

MR. RISLOV: Do you have any sort of schedule that would show the distribution or the frequency? Or

let me put this way. I believe there were 26 customers showing exactly what they did use during the test year and what type of customer they would be.

For instance, someone knowing that 51,000 is an average and seeing the break even is 110, so I'm using 100,000 therms could make a significant difference in that average. In other words, we could have people consuming much less than 51 therms under this rate.

MR. HITCHCOCK: Yes. You have customers in that category that are in the 20,000 range when you look at grade schools.

MR. BETTMANN: I did put together a spreadsheet on a month-by-month basis on their response with all the information and did some -- I ran some numbers on what the increase would be for each customer.

Part of the problem turning it over to an annual, some of these customers are -- or several of them were on for less than a year, so there's some that -- some of the schools were on for ten months, eight months, and one was -- one school system was only for some six months.

MR. RISLOV: When you say on for six months, they've only been a customer for six months?

MR. BETTMANN: On this rate, yeah. I assume they were customers.

MR. HITCHCOCK: They would have been sales customers prior to that.

MR. RISLOV: So for someone consuming 20,000 therms, the customer charge would have an approximate effect of 3.6 cents a therm customer charge alone; is that correct?

MR. BETTMANN: I didn't do it on that basis. I did it by customer. Customer base I didn't do it.

MR. RISLOV: Do you have any idea what customers consuming 20,000 therms would incur as a percentage rate increase under this rate design?

MR. BETTMANN: You would have to take the difference in the charge per therm of where it goes from .0364 to .0388. What's that? 2410024 times your 20,000, and that's -- you get a dollar amount.

MR. RISLOV: I understand that. I asked if you had maybe done that.

MR. BETTMANN: Not for 20,000, not a number, no, I did not. A typical bill, I did actual bills.

MR. HITCHCOCK: On a customer that used 20,000 therms a year, the customer charge going up 60 would cost an additional $720 annually, divided by 20,000 therms comes out 3.6 cents per therm increase.

MR. RISLOV: Yeah, I had calculated that already. I just wondered that combined with the commodity charge, what that percentage effect would be annually to that customer.

I guess my question is there's really no information we have that would break out the commodity consumption on a customer-by-customer basis because there are only 26 customers. Your averages can be skewed by just a few larger consuming customers.

So I think the concern at least that I would have is this type of customer charge increase, coupled with that commodity increase could lead toward a rate increase for certain customers in this class that's going to look relatively remarkable.

MR. BETTMANN: Well, I did run some numbers both ways without assumed gas costs in there and with the gas cost of all the customers and it does vary without the gas costs element in there, because they've got to pay for the gas too.

So their total energy, what I refer to the total energy bill, with just the rates, if you looked at just the rates, some of the customers would see as much as 30, 35 percent increase. And there's a couple large ones that were only on for two months, but they would be down around six, seven percent.

MR. RISLOV: And the reason -- and I understand, Martin, when we wouldn't be considering gas costs. But as Mr. Towers had explained, he's looking at this rate increase as a non-gas type of rate increase. So I'm trying to make an apples/apples comparison for what these customers would receive as an increase.

MR. BETTMANN: Based on actual usage, some of these were only six months, so a couple of them were ten months, you would have some of their higher -- it would be like January and February loads were in there, which would skew this a little bit, would lower the percentages.

Some of the individual customers go a little bit over 40 percent, but they were on school systems where they would have three or four schools. Actually one goes to 60 percent, one individual customer. So you're right, you do see that, but when you combine them for the entire school system, the combined effect is down below 40 percent.

MR. RISLOV: So I take it these increases would apply to schools?

MR. BETTMANN: There are three different school systems.

MR. RISLOV: When you say combined --

MR. BETTMANN: They're larger towns and they had three or four schools on, you know.

MR. RISLOV: So it's the same school system but multiple schools within that system.

MR. BETTMANN: Multiple customers, right. I calculated it both ways for the individual schools and then as a combined bill. I assume they get -- you know, individual schools don't pay for it, the school district pays for it.

COMMISSIONER SCHOENFELDER: Okay. But you're saying that there are individual schools amongst these 26 where the school district is part of the 26? I thought I understood this.

MR. BETTMANN: The individual schools are part of the 26.

COMMISSIONER SCHOENFELDER: Okay. Then all right. Are there other kinds, other entities besides schools that are only on for a short period of time? Is this still the function of the whole class of customers? Is this the function of them just being part of that class a short period of time, or are there some customers who only will be purchasing gas under the transportation rate during certain times of the year consistently? I need that clarified a little more. I thought Tom had told me.

MR. BETTMANN: Well, I think what we're seeing is that these school systems went to this rate partway through the year so we don't -- it's not like they get on and get off. They just didn't get on in the middle of the year.

COMMISSIONER SCHOENFELDER: That's what I thought he said. And further on I began to wonder if there were some that would only be part of the year be transportation customers.

MR. BETTMANN: I don't think so. They would probably, like he suggested, they probably lock in their gas costs for a year and then they may decide from year to year.

COMMISSIONER SCHOENFELDER: But they still have another option to go to the sales service if this does not prove to be economical for them? And they will be offered that option by the company, will they, Tom?

MR. HITCHCOCK: Yes.

COMMISSIONER NELSON: Of the 26 customers that are affected, how many of those are schools?

MR. BETTMANN: 12, 12 different individual schools.

CHAIRMAN BURG: How many districts?

MR. BETTMANN: It affects four districts.

CHAIRMAN BURG: Because they're going to get -- even if they have separate schools, they're going to get the advantage of combining them on the purchasing of the gas. So to look at them as separate schools and the effect is not really a true picture for this purpose, right?

MR. BETTMANN: I wouldn't think so.

CHAIRMAN BURG: I mean it just means you've got a meter at those separate buildings and that's why they have to be classified a separate customer. But they have combined the usage to take advantage of the transportation rate?

MR. BETTMANN: I don't know. I don't know how that works for sure. I assume they were supplier buys and this is how the distribution breaks down for each of schools.

MR. HITCHCOCK: Right. On these school districts in general, most of them have, you know, four or five of these accounts that are big enough to transport; and they just get a contract that says we'll pay for that distribution transportation. They line up a supplier, that supplier brings gas to NPS and they can lock in a fixed price.

I think that's generally why the school districts, you know, go for this. Now, not every

school district does it. I believe Aberdeen, Mitchell, Brookings, and Sioux Valley School does that.

But they find that transportation is attractive from the standpoint they can budget their annual cost. And there are some individuals at the schools that kind of watch the gas markets and are kind of business savvy and they like to get down there where now is the time to lock in and they're mitigating any risk of the market running up. They run it like a business.

But I think that, you know, I am concerned about individual customers and the impacts that our rate change would have on individual customers. But certainly at the same time we went through a pretty extensive cost allocation class, cost of service allocation study to determine the cost of providing gas delivery service to each class of customer.

And unfortunately within even classes of customers there are, you know, changes. I mean just even in the residential customer class, if you have a small user, an increase from 1.50 or 4.50 to $6.00 on a customer charge is going to cause that individual to have a higher annual increase in cost than someone that uses twice the gas that's in the average. But that's what happens.

CHAIRMAN BURG: Well, and I'm conscious of the fact that if we don't allocate it here that means that those people are being subsidized by somebody else.

MR. HITCHCOCK: If we don't collect the costs from these school districts, someone else will have to pick up the tab. It will either be large customers where, you know, it gets very competitive to attract those to Northwestern's system or residential and small customers.

Now, it's probably a minor, minor change, you know, that those costs to spread those over the rest of the customers, but I think we attempted to come up with rates that were fair and equitable for the service that that customer wanted. And these customers have elected transportation service and have found that to be in their best interests. If those costs now become higher than what they need to be for their economic purposes, then they can truly go back to sales service.

CHAIRMAN BURG: Anything else?

MR. RISLOV: Tom, are all of these customers using gas for space heating? It doesn't seem --

MR. HITCHCOCK: Yes.

MR. RISLOV: They are?

MR. HITCHCOCK: What you find generally the

customers that the school districts a vast majority of the gas consume theire for space heating and for running their stoves for cooking purposes during the school term. When you get to the summer months, they're absolutely almost zero consumption. You do have a few smaller customers in there light industrial that have chosen transportation, a few.

I think there's even a couple colonies that are small enough they're below the 110,000 threshold so if they're going to transport that's the best rate to be on.

MR. RISLOV: I'd have one question for Mr. Towers as well. In going through the information that was submitted yesterday in support of the settlement, I didn't think it was quite clear exactly what happened in the relationship between the capital structure and ROE.

It appeared the return on equity was actually lowered by staff by about 45 basis points, so that naturally had to reflect considerable movement in the cap structure. And I was looking for a little more explanation of why staff agreed to make that movement from what was initially filed.

MR. TOWERS: Okay. Are you looking at a memo that was distributed yesterday?

MR. RISLOV: I believe for more clarification in the settlement, I think as you stated this morning, the settlement ROE was 10.25. In the initial filing staff's ROE was 10.69. Of course they conditioned that on the low amount of equity in the capital structure to approximately 37 percent.

So the movement I saw yesterday was actually reduction in ROE, therefore it appeared to me that there had to be a fairly significant change, as you mentioned this morning there was in the cap structure moving the equity portion from 37 to 46.

I guess the whole of this question is to determine exactly what led staff to make that change.

MR. TOWERS: Well, I think it's a combination of things. The capital structure and associated return on equity discussion that you'll find in Basil Copeland's testimony is rather complicated because he was first looking at capital structure and saying that the corporate -- Northwestern Corporation capital structure was not appropriate, that it reflected all these non-utility activities that Northwestern Corporation was engaged in.

And so he, Copeland, made significant adjustments to the capital structure, reducing the equity down to, I think, around 37 percent.

He then studied the cost of equity and reached certain conclusions which were related, as I recall -- and now I'm trying to recall his testimony. But his studies were related to a different capital structure that is to the overall corporate capital structure. But he wanted to apply them to an adjusted capital structure and that's how he ended up moving from a nine to 10 percent range for cost of equity to a higher figure associated with his lower ratio.

So you had to look at the two things together. And I try to simplify that in my memo that I had prepared and that was like being at this morning for my explanation of the settlement agreement and why staff supported it.

Combining those, the movement -- the ultimate movement on capital structure and rate of return, observing that the end result was a coverage of interest of about 2.9 times, which in Copeland's view was -- and this is not in his testimony -- was ample but not excessive.

And in recognizing that the company was coming from an 11 1/4 percent return on equity looking at return on equity in isolation in their request, which in turn was based on what was granted to them in the last rate case, moving that down to 10 1/4 percent

was a significant benefit to rate payers.

And even the capital structure, I believe, was either -- is either about the same in this settlement agreement as it was in the settlement of the last case, or the equity ratio is no higher than it was at that time.

I don't think I've really been able to answer your question explicitly but and that's one reason I tried to view the settlement in some simpler and more generic terms, I guess, on those two issues. It got very complicated because of the three different capital structures, the equity cost study that related to one but then applied to a different capital structure.

And I just -- I was unable -- personally I would defer to Basil to explain all those interrelationships, as I think he's done in that filed testimony. I don't know if I've been any help or not.

MR. HITCHCOCK: Greg, I'll try to explain it as best I can. The position that Basil took in his testimony was that he took the stand-alone capital structure of Northwestern Public Service and eliminated 85 million dollars of common equity related to investments in affiliates and applied a 10.7 return on equity on that capital structure, which had about a 36 percent common equity component.

He said if he just used the stand-alone capital restructure restoring the 85 million, then his recommendation on return equity would be 10 percent. They produce the same answer or reduction in cost. And so all that Basil moved was from 10 to 10 1/4. That's how that piece fits. It really wasn't that the company accepted a reduction from what the staff gave as 10.7 percent return on equity down to 10 1/4 because it was a different capital structure also.

MR. TOWERS: That's correct.

MR. RISLOV: I guess my question I thought it was somewhat novel, but Basil had proposed in his initial filing -- and maybe this is from my own understanding more so than for its effect on the settlement. But perhaps at some later point I can maybe get a little more detail on that just for my own information. Thank you.

CHAIRMAN BURG: Are there any other questions? If not, we will take it under advisement, the settlement proposal that we received from both staff and the company.

MR. MOLSTAD: Mr. Chairman, we would like to offer the settlement agreement and the attachments into the record for purposes of your consideration and approval.

CHAIRMAN BURG: Are there any objections to the entering of the settlement?

MS. CREMER: None.

CHAIRMAN BURG: The settlement will be received.

MS. WIEST: We will immediately go into the unsettled portion of that. Take a ten-minute break and start.

(THIS PART OF THE HEARING CONCLUDED AT 10:00 A.M.)

STATE OF SOUTH DAKOTA)
)
COUNTY OF HUGHES)

I, LORI J. GRODE, Registered Merit Reporter and Notary Public in and for the State of South Dakota:

DO HEREBY CERTIFY that the above hearing, pages 1 through 47, inclusive, was recorded stenographically by me and reduced to typewriting.

I FURTHER CERTIFY that the foregoing transcript of the said hearing is a true and correct transcript of the stenographic notes at the time and place specified hereinbefore.

I FURTHER CERTIFY that I am not a relative or employee or attorney or counsel of any of the parties, nor a relative or employee of such attorney or counsel, or financially interested directly or indirectly in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and seal of office at Pierre, South Dakota, this 21st day of October 1999.

Lori J. Grode, RMR, RPR

STATE OF SOUTH DAKOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

RECEIVED
OCT 19 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

In the Matter of the Application)
of NorthWestern Public Service)
For Authority to Increase Natural Gas)
Rates in South Dakota)

Docket No. NG99-002

EXHIBIT
7
10-20-99

SETTLEMENT AGREEMENT BETWEEN NORTHWESTERN PUBLIC SERVICE AND COMMISSION STAFF

This Settlement Agreement is made and entered into by and between NorthWestern Public Service (the "Company"), a division of NorthWestern Corporation, and the Staff of the South Dakota Public Utilities Commission ("Staff").

I.

BACKGROUND

On June 1, 1999, the Company filed an application with the Public Utilities Commission ("Commission") for an increase in South Dakota revenue to the Company of $2,108,112 or approximately 6% based on the test year ending December 31, 1998, as adjusted. The Company cited increased costs of operation and its expanded distribution system since its last general rate increase, filed in 1994, as the reasons for the proposed change in rates.

On June 25, 1999, the Commission filed a notice of opportunity to intervene. No petitions to intervene have been received by the Commission.

The Staff submitted numerous data requests to the Company during the course of the Staff investigation. On September 24, 1999, Commission Staff filed the testimony of Robert G. Towers, David Jacobson, Martin C. Bettmann, Michele M. Farris, Keith A. Senger and Basil L. Copeland, Jr.. Commission Staff recommended an increase in Company revenue of $402,290 which reflected a disallowance related to the Nekota pipeline. During and following the receipt of the data responses from the Company, the Staff and the Company engaged in numerous discussions relating to the settlement of a variety of issues. The procedural schedule related to the Company's time to file rebuttal testimony was

suspended by the Commission based upon the representations by the Company and the Staff that a substantial agreement concerning the settlement of the proceeding had been reached.

II.

ELEMENTS OF THE SETTLEMENT AGREEMENT

Article I. Revenue Requirement

The Company and the Staff agree that, if the Commission approves this Settlement Agreement ("Agreement"), the Company will file revised rate schedules to produce an annual increase in base rate revenue levels (i.e., excluding purchased gas cost adjustment and sales taxes) of $1,279,025 applicable to retail natural gas service. The revised rate schedules shall be effective for billings rendered on and after December 1, 1999, provided there is Commission approval of this Agreement and the revised rate schedules.

Article II. Rate Design

The agreed to change in rates would affect customer classes by the following percentages:

Class	% Increase
Residential – Rate 81	3.8
Small Commercial – Rate 82	3.9
Large Commercial/Industrial Firm Rate 84 (Option A)	1.6
Large Commercial/Industrial Rate 84 (Option B)	1.5
Large Commercial/Industrial Interruptible – Rate 85 (Option A)	1.8
Large Commercial/Industrial Interruptible – Rate 85 (Option B)	1.4
Transportation – Rate 87 (Option A)	22.5
Transportation – Rate 87 (Option B)	9.1
Contracts with Deviations	1.5
Total South Dakota	3.8

Article III. Other Conditions

The parties agree to a return on common equity of 10.25% and that Company's capital structure shall be based on its stand alone capital structure rather than a consolidated capital structure.

It is further agreed by the parties that the Nekota pipeline issue which was raised by Commission Staff has been eliminated from the base rate determination, and alternatively will be heard as a Purchase Gas Adjustment request before the Public Utilities Commission on October 20, and October 21, 1999 as a separate proceeding from the base rate determination.

It is further agreed by the parties that the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, contracts between the Company and any separate affiliated company that does business with the Company, related to the Company's utility business in South Dakota. Such contracts will identify the products and services to be provided by the affiliate to the Company and will provide that the pricing of such products and services shall be based upon the affiliate's costs, which costs include a reasonable profit for the affiliate. The Company will maintain and, upon Commission or Commission Staff request, furnish information supporting the basis of the pricing of such products and services, whether based on costs of labor and materials provided or specific allocations of joint or common costs. In addition, the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, an explanation of NorthWestern Corporation expenses or allocations charged to the Company. Thereafter, June 30th of each year (beginning June 30, 2000), the Company will file with the Commission any new or revised contracts with each affiliate doing business with the Company and a statement of all transactions between the Company and each affiliate during the preceding calendar year, as well as any changes in the methodology for the charging of any NorthWestern Corporation expenses or allocations to the Company.

Article IV General Conditions

1. It is agreed that this Agreement is a negotiated dollar settlement and establishes no principles or precedent and shall not be deemed to foreclose the Company or the Staff or any other person from making any contention in any proceeding or investigation, including the right of the Staff or any other interested person to seek a rate change if justified on any basis.

2. Approval of this Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this proceeding.

3. The Agreement is expressly conditioned upon the Commission's acceptance of all the provisions thereof, without change or condition which is unacceptable to any party.

4. Discussions between the Company and the Staff which produced this Agreement have been conducted with the customary understanding that all offers of settlement and discussions relating thereto are privileged and shall not be used in any manner in connection with this proceeding or otherwise, except as required by law.

5. This Agreement includes all terms of Settlement and is submitted on the condition that in the event the Commission imposes any change in or condition to this Agreement which is unacceptable to any party, this Agreement shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding or be used for any other purpose.

6. This Agreement shall be binding upon the parties hereto, and upon their successors, assigns, agents and representatives.

7. It is understood that the Staff enters into this Agreement for the benefit of the Company's South Dakota natural gas customers affected hereby.

8. This Agreement is entered into by and between the Company and the Staff by their respective agents who represent that they are fully authorized to do so on behalf of their principals.

Staff of the South Dakota
Public Utilities Commission

By Karen E. Cremer
Title Staff Attorney
Dated: October 19, 1999

NorthWestern Public Service
a division of NorthWestern Corporation

By _____
Title President & CEO
Dated October 19, 1999

Attached to this Settlement Agreement and incorporated herein are the attached schedules.

Northwestern Public Service
South Dakota - Gas
Revenue Increase
Per Staff

Line No.	RATE STEP	THERMS (A)	THERMS (B)	TOTAL MARGIN (C) Test Year Revenue	REVISED (D) Proposed Revenue	INCREASE (F) Revenue (Inc./Dec.)	PERCENT INCREASE (G) Percent (Inc./Dec.)
	REVENUE INCREASE by RATE CODE						
1	RATE 81	33,197,790	33,197,790	20,189,402	20,961,369	**771,967**	3.8%
2	RATE 82	15,866,880	15,866,880	8,226,248	8,546,645	**320,397**	3.9%
3	RATE 84 (OPTION A&B)	5,936,020	5,936,020	2,235,630	2,269,986	34,356	1.5%
4	RATE 85 (OPTION A&B)	4,425,500	4,425,500	1,431,062	1,455,934	24,871	1.7%
5	RATE 87 (OPTION A&B)	29,121,130	29,121,130	1,211,082	1,334,781	123,699	10.2%
6	COMBINED RATE 84, 85, and 87 Sum of Line 3, 4, and 5	39,482,650	39,482,650	4,877,775	5,060,701	**182,926**	3.8%
7	CONTRACTS with DEVIATIONS	10,400,310	10,400,310	196,440	199,376	**2,936**	1.5%
8	TOTAL (Sum of Lines 1, 2, 6, and 7)	98,947,630	98,947,630	$ 33,489,865	$ 34,768,090	$ **1,278,226**	3.8%

Northwestern Public Service
South Dakota - Gas
Residential - Rate 81 and Small Commercial - Rate 82
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Residential - Rate Code 81**									
2										
3		ALL THERMS CURRENTLY (FIRST 30)	Therms	9,414,430	9,414,430	0.2000	0.2055	1,882,886	1,934,665	51,779
4		EXCESS	Therms	23,783,360	23,783,360	0.1220	0.1270	2,901,570	3,020,487	118,917
5										
6		CUSTOMER CHARGE	BILL	400,847	400,847	4.50	6.00	1,803,812	2,405,082	601,271
7										
8		AD VALOREM TAX ADJUSTMENT		33,197,790	33,197,790	0.0156	0.0156	517,886	517,886	0
9		MGP REMOVAL COST ADJUSTMENT		33,197,790	33,197,790	0.0140	0.0140	464,769	464,769	0
10		GAS COST COMMODITY CHARGE		33,197,790	33,197,790	0.2043	0.2043	6,782,308	6,782,308	0
11		GAS COST DEMAND CHARGE		33,197,790	33,197,790	0.1758	0.1758	5,836,171	5,836,171	0
12										
13		TOTAL		33,197,790	33,197,790			20,189,402	20,961,369	771,967
								6,588,267		
14	**Small Commercial - Rate Code 82**									
15										
16		ALL THERMS CURRENTLY (FIRST 400)	Therms	8,490,570	8,490,570	0.1141	0.1309	968,774	1,111,416	142,642
17		NEXT 1,600	Therms	6,106,520	6,106,520	0.0841	0.0891	513,558	544,091	30,533
18		EXCESS	Therms	1,269,790	1,269,790	0.0541	0.0541	68,696	68,696	0
19										
20		CUSTOMER CHARGE	BILL	58,889	58,889	4.50	7.00	265,001	412,223	147,223
21										
22		AD VALOREM TAX ADJUSTMENT		15,866,880	15,866,880	0.0099	0.0099	157,082	157,082	0
23		MGP REMOVAL COST ADJUSTMENT		15,866,880	15,866,880	0.0140	0.0140	222,136	222,136	0
24		GAS COST COMMODITY CHARGE		15,866,880	15,866,880	0.2043	0.2043	3,241,604	3,241,604	0
25		GAS COST DEMAND CHARGE		15,866,880	15,866,880	0.1758	0.1758	2,789,398	2,789,398	0
26										
27		TOTAL		15,866,880	15,866,880			8,226,248	8,546,645	320,397

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Firm - Rate 84 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Large Commercial/Industrial Firm - Rate Code 84 (Option A)**									
2										
3		ALL THERMS	Therms	5,505,570	5,505,570	0.0364	0.0388	200,403	213,616	13,213
4										
5		CUSTOMER CHARGE	BILL	1,963	1,963	70.00	80.00	137,410	157,040	19,630
6										
7		AD VALOREM TAX ADJUSTMENT		5,505,570	5,505,570	0.0064	0.0064	35,236	35,236	0
8		MGP REMOVAL COST ADJUSTMENT		5,505,570	5,505,570	0.0140	0.0140	77,078	77,078	0
9		GAS COST COMMODITY CHARGE		5,505,570	5,505,570	0.2300	0.2300	1,266,281	1,266,281	0
10		GAS COST DEMAND CHARGE		425,480	425,480	0.8700	0.8700	370,168	370,168	0
11		RELEASE CAPACITY/BALANCING SURCHARGE		680,040	680,040	0.0170	0.0170	11,561	11,561	0
12		SUBTOTAL		5,505,570	5,505,570			2,098,136	2,130,979	32,843
13	**Large Commercial/Industrial Firm - Rate Code 84 (Option B)**									
14										
15		ALL THERMS	Therms	430,450	430,450	0.0180	0.0204	7,748	8,781	1,033
16										
17		CUSTOMER CHARGE	BILL	24	24	260.00	280.00	6,240	6,720	480
18										
19		AD VALOREM TAX ADJUSTMENT		430,450	430,450	0.0042	0.0042	1,808	1,808	0
20		MGP REMOVAL COST ADJUSTMENT		430,450	430,450	0.0140	0.0140	6,026	6,026	0
21		GAS COST COMMODITY CHARGE		430,450	430,450	0.2300	0.2300	99,004	99,004	0
22		GAS COST DEMAND CHARGE		18,120	18,120	0.8700	0.8700	15,764	15,764	0
23		RELEASE CAPACITY/BALANCING SURCHARGE		53,180	53,180	0.0170	0.0170	904	904	0
		SUBTOTAL		430,450	430,450			137,494	139,007	1,513
24										
25		TOTAL		5,936,020	5,936,020			$2,235,630	$2,269,986	$34,356

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial									
1	**Interruptible - Rate Code 85 (Option A)**									
2										
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451
4										
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290
6										
7		AD VALOREM TAX ADJUSTMENT		3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0
8		MGP REMOVAL COST ADJUSTMENT		3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0
9		GAS COST COMMODITY CHARGE		3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0
10		RELEASE CAPACITY/BALANCING SURCHARGE		3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741
	Large Commercial/Industrial									
12	**Interruptible - Rate Code 85 (Option B)**									
13										
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171
15										
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960
17										
18		AD VALOREM TAX ADJUSTMENT		487,770	487,770	0.0042	0.0042	2,049	2,049	0
19		MGP REMOVAL COST ADJUSTMENT		487,770	487,770	0.0140	0.0140	6,829	6,829	0
20		GAS COST COMMODITY CHARGE		487,770	487,770	0.2300	0.2300	112,187	112,187	0
21		RELEASE CAPACITY/BALANCING SURCHARGE		487,770	487,770	0.0170	0.0170	8,292	8,292	0
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131
23										
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Transportation - Rate Code 87 (Option A)**									
2										
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191
4										
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720
6										
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0
10	SUBTOTAL			1,329,490	1,329,490			97,355	119,266	21,911
11	**Transportation - Rate Code 87 (Option B)**									
12										
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	566,949	66,700
14										
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320
16										
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0
20	SUBTOTAL			27,791,640	27,791,640			1,113,727	1,215,515	101,788
21										
22	TOTAL			29,121,130	29,121,130			1,211,082	1,334,781	123,699

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Contracts with Deviations**									
2										
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320
4										
5		CUSTOMER CHARGE	BILL	36	36	260.00	330.00	9,360	11,880	2,520
6										
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)
10										
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$4.50	$6.00
2	FIRST 30 THERMS	$0.20000	$0.20550
3	EXCESS THERMS	$0.12200	$0.12700
4	PGA and OTHER ADJ.	$0.40970	$0.40970

Residential - Rate Code 81

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$4.50	$6.00	$1.50	33.33%
6	10	10.60	12.15	1.56	14.67%
7	25	19.74	21.38	1.64	8.29%
8	50	33.43	35.19	1.77	5.28%
9	75	46.72	48.61	1.89	4.05%
10	80	49.36	51.29	1.92	3.88%
11	100	60.01	62.03	2.02	3.36%
12	125	73.30	75.44	2.14	2.92%
13	150	86.60	88.83	2.27	2.62%
14	175	99.89	102.28	2.39	2.39%
15	200	113.18	115.70	2.52	2.22%
16	225	126.47	129.11	2.64	2.09%
17	250	139.77	142.53	2.77	1.98%
18	300	166.35	169.37	3.02	1.81%
19	400	219.52	223.04	3.52	1.60%
20	500	272.69	276.71	4.01	1.47%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	196	$110.80	$113.29	$2.49	2.2%
FEB	168	$95.22	$97.57	$2.35	2.5%
MAR	148	$85.71	$87.97	$2.26	2.6%
APR	126	$73.80	$75.95	$2.14	2.9%
MAY	49	$32.65	$34.40	$1.76	5.4%
JUN	23	$18.81	$20.44	$1.63	8.7%
JUL	18	$15.77	$17.37	$1.60	10.2%
AUG	15	$13.58	$15.17	$1.58	11.6%
SEP	14	$13.27	$14.85	$1.58	11.9%
OCT	32	$23.76	$25.43	$1.67	7.0%
NOV	82	$50.27	$52.19	$1.92	3.8%
DEC	118	$69.77	$71.88	$2.11	3.0%
TOTAL	988	$603.41	$626.51	$23.09	3.8%

AVERAGE MONTHLY USE = 82 Therms

LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$4.50	$7.00
22	FIRST 400 THERMS	$0.11410	$0.13090
23	NEXT 1,600 THERMS	$0.08410	$0.08910
24	EXCESS THERMS	$0.05410	$0.05410
25	PGA and OTHER ADJ.	$0.40970	$0.40970

SMALL COMMERCIAL - Rate Code 82

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
26	0	4.50	7.00	$2.50	55.56%
27	50	30.69	34.03	3.34	10.88%
28	100	56.88	61.06	4.18	7.35%
29	200	109.26	115.12	5.86	5.36%
30	350	187.83	196.21	8.38	4.46%
31	500	263.40	273.12	9.72	3.69%
32	750	386.85	397.82	10.97	2.84%
33	1000	510.30	522.52	12.22	2.39%
34	1500	757.20	771.92	14.72	1.94%
35	2000	1,004.10	1,021.32	17.22	1.71%
36	2500	1,236.00	1,253.22	17.22	1.39%
37	3,000	1,467.90	1,485.12	17.22	1.17%
38					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	621	316.57	325.79	9.22	2.9%
FEB	577	298.21	305.43	9.22	3.1%
MAR	503	261.61	270.83	9.22	3.5%
APR	397	212.54	221.71	9.17	4.3%
MAY	136	76.60	81.42	4.81	6.3%
JUN	68	40.28	43.93	3.65	9.1%
JUL	60	35.92	39.43	3.51	9.8%
AUG	54	32.83	36.24	3.41	10.4%
SEP	50	30.92	34.27	3.35	10.8%
OCT	90	51.90	55.92	4.02	7.7%
NOV	261	141.25	148.13	6.89	4.9%
DEC	394	210.73	219.85	9.11	4.3%
TOTAL	3,214	$1,707	$1,783	$75.58	4.4%

39 AVERAGE MONTHLY USE = 268 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
38	CUSTOMER CHARGE	$70.00	$80.00
39	ALL THERMS	$0.03640	$0.03880
40	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION A)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
41	0	70.00	80.00	$10.00	14.29%
42	250	141.70	152.30	10.60	7.48%
43	500	213.40	224.60	11.20	5.25%
44	750	285.10	296.90	11.80	4.14%
45	1,000	356.80	369.20	12.40	3.48%
46	1,500	500.20	513.80	13.60	2.72%
47	2,000	643.60	658.40	14.80	2.30%
48	3,000	930.40	947.60	17.20	1.85%
49	4,000	1,217.20	1,236.80	19.60	1.61%
50	5,000	1,504.00	1,526.00	22.00	1.46%
51	6,000	1,790.80	1,815.20	24.40	1.36%
52	7,000	2,077.60	2,104.40	26.80	1.29%
53	8,000	2,364.40	2,393.60	29.20	1.23%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	6,298	1,876.18	1,901.29	25.11	1.3%
FEB	5,230	1,569.94	1,592.49	22.55	1.4%
MAR	4,715	1,422.15	1,443.48	21.32	1.5%
APR	4,008	1,219.43	1,239.04	19.62	1.6%
MAY	2,138	683.28	698.41	15.13	2.2%
JUN	392	182.53	193.47	10.94	6.0%
JUL	1,376	464.76	478.07	13.30	2.9%
AUG	737	281.46	293.23	11.77	4.2%
SEP	658	258.59	270.17	11.58	4.5%
OCT	1,287	439.09	452.18	13.09	3.0%
NOV	2,808	875.33	892.07	16.74	1.9%
DEC	3,471	1,065.37	1,083.70	18.33	1.7%
TOTAL	33,118	$10,338	$10,538	$199.48	1.9%

54 AVERAGE MONTHLY USE = 2,760 Therms

LINE NO.		PRESENT	PROPOSED
55	CUSTOMER CHARGE	$260.00	$280.00
56	ALL THERMS	$0.01800	$0.02040
57	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION B)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
58	0	260.00	280.00	$20.00	7.69%
59	250	327.10	347.70	20.60	6.30%
60	500	394.20	415.40	21.20	5.38%
61	1,000	528.40	550.80	22.40	4.24%
62	2,500	931.00	957.00	26.00	2.79%
63	5,000	1,602.00	1,634.00	32.00	2.00%
64	10,000	2,944.00	2,988.00	44.00	1.49%
65	20,000	5,628.00	5,696.00	68.00	1.21%
66	35,000	9,654.00	9,758.00	104.00	1.08%
67	50,000	13,680.00	13,820.00	140.00	1.02%
68	60,000	16,364.00	16,528.00	164.00	1.00%
69	70,000	19,048.00	19,236.00	188.00	0.99%
70	75,000	20,390.00	20,590.00	200.00	0.98%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	70,064	19,065.09	19,253.24	188.15	1.0%
FEB	32,177	8,896.28	8,993.51	97.22	1.1%
MAR	28,048	7,787.98	7,875.29	87.31	1.1%
APR	19,295	5,438.85	5,505.16	66.31	1.2%
MAY	12,867	3,713.40	3,764.28	50.88	1.4%
JUN	5,147	1,641.43	1,673.79	32.35	2.0%
JUL	1,253	596.44	619.45	23.01	3.9%
AUG	377	361.19	382.09	20.90	5.8%
SEP	811	477.67	499.62	21.95	4.6%
OCT	3,412	1,175.79	1,203.98	28.19	2.4%
NOV	10,386	3,047.62	3,092.55	44.93	1.5%
DEC	31,388	8,664.51	8,779.84	95.33	1.1%
TOTAL	215,224	$60,886	$61,643	$756.54	1.2%

71 AVERAGE MONTHLY USE = 17,935 Therms

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
	Large Commercial/Industrial										
1	**Interruptible - Rate Code 85 (Option A)**										
2											
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451	
4											
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290	
6											
7	AD VALOREM TAX ADJUSTMENT			3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0	
8	MGP REMOVAL COST ADJUSTMENT			3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0	
9	GAS COST COMMODITY CHARGE			3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0	
10	RELEASE CAPACITY/BALANCING SURCHARGE			3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0	
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741	1.8%
	Large Commercial/Industrial										
12	**Interruptible - Rate Code 85 (Option B)**										
13											
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171	
15											
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960	
17											
18	AD VALOREM TAX ADJUSTMENT			487,770	487,770	0.0042	0.0042	2,049	2,049	0	
19	MGP REMOVAL COST ADJUSTMENT			487,770	487,770	0.0140	0.0140	6,829	6,829	0	
20	GAS COST COMMODITY CHARGE			487,770	487,770	0.2300	0.2300	112,187	112,187	0	
21	RELEASE CAPACITY/BALANCING SURCHARGE			487,770	487,770	0.0170	0.0170	8,292	8,292	0	
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131	1.4%
23											
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871	1.7%

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	**Transportation - Rate Code 87 (Option A)**										
2											
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191	
4											
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720	
6											
7		EXTENDED SERVICE RIDER DISCOUNT						0	0	0	
8		AD VALOREM TAX ADJUSTMENT		1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0	
9		MGP REMOVAL COST ADJUSTMENT		1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0	
10		SUBTOTAL		1,329,490	1,329,490			97,355	119,266	21,911	22.5%
11	**Transportation - Rate Code 87 (Option B)**										
12											
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	566,949	66,700	
14											
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320	
16											
17		EXTENDED SERVICE RIDER DISCOUNT						(42,090)	(47,322)	(5,232)	
18		GAS COST COMMODITY CHARGE		27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0	
19		RELEASE CAPACITY/BALANCING SURCHARGE		27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0	
20		SUBTOTAL		27,791,640	27,791,640			1,113,727	1,215,515	101,788	9.1%
21											
22		TOTAL		29,121,130	29,121,130			1,211,082	1,334,781	123,699	10.2%

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	**Contracts with Deviations**										
2											
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320	
4											
5		CUSTOMER CHARGE	BILL	36	36	260.00	330.00	9,360	11,880	2,520	
6											
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0	
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0	
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)	
10											
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936	1.5%

THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

RECEIVED
OCT 27 1999
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	NG99-002 TRANSCRIPT OF CONTESTED CASE

HEARD BEFORE THE PUBLIC UTILITIES COMMISSION

PROCEEDINGS:	October 20, 1999 10:00 A.M. Room 413, Capitol Building Pierre, South Dakota
PUC COMMISSION:	Jim Burg, Chairman Laska Schoenfelder, Commissioner Pam Nelson, Commissioner
COMMISSION STAFF PRESENT:	Rolayne Ailts Wiest Karen Cremer Gregory A. Rislov David Jacobson Martin Bettmann
Reported by:	Lori J. Grode, RMR

ORIGINAL

APPEARANCES

For NWPS: Mr. Russell C. Molstad, Jr.
600 Market Street West
Huron, South Dakota, 57350

and

Mr. Alan D. Dietrich
125 S. Dakota Ave., #1100
Sioux Falls, South Dakota, 57104

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P R O C E E D I N G S

CHAIRMAN BURG: I think we'll go ahead and get started again. I think Bob left us, didn't he? He's no longer on the phone? We don't have anybody on the phone; right? Of course they can't testify on it anyway.

I'm going to turn it over to Rolayne at this time to conduct the hearing on this issue.

MS. WIEST: We'll now move from the settlement portion to the contested case portion of the hearing. And are there any motions or opening statements on this issue by NPS or staff?

MR. MOLSTAD: Yes, we do.

MS. WIEST: Go ahead.

MR. MOLSTAD: Thank you very much. Thank you very much, Rolayne, Commission, staff. I do have a couple comments here to start this matter.

First of all, I want to again point out that this particular hearing is a separate proceeding apart from docket number NG99-002, separate and apart from the rate case that we have just discussed earlier.

The issue here is to determine the reasonableness of the $576,000 in costs paid by Northwestern Public Service to Northwestern Energy Corporation for capacity on the Aberdeen pipeline, also

which would be referred to as the Nekota pipeline in this proceeding.

And that this particular issue would only be decided based upon the testimony on the record developed at this particular hearing and not on any other information or any filings that were made part of the gas case NG99-002.

That the company, through its witnesses, will show the reasonableness of those costs and that they should be continued to be included in the Northwestern Public Services purchased gas adjustment cost.

MS. WIEST: Okay.

MR. MOLSTAD: That's all I have.

MS. CREMER: Thank you. Staff believes the issue in this case is really quite simple and that is what is the appropriate rate that should be paid for capacity on the Nekota pipeline since its inception in 1996.

Staff believes that the evidence will show that the rate currently being charged is excessive and therefore it requires a refund in the amount of $1,297,383.78.

MR. MOLSTAD: May I respond to that, please?

MS. WIEST: Go ahead.

MR. MOLSTAD: If you're done?

MS. CREMER: I'm done.

MS. WIEST: Go ahead.

MR. MOLSTAD: Northwestern's position is that the -- that there is no refund to be paid, first of all. We would argue that the charges were reasonable and continue to be reasonable.

But that the staff -- there's no provision that would allow a refund based upon the purchased gas adjustment statutes in that the purchased gas adjustment for this $576,000 for the Nekota/Aberdeen pipeline has been provided and filed with the Commission since its inception; that it has been approved, has not been objected to by the Commission, under the statute 49-34(a)-25 whereby any objection to any purchased gas adjustment request such as the Nekota/Aberdeen pipeline would have had to be made within ten days of that particular filing.

And since that wasn't done, it's automatically approved, and also because the tariffs had been approved in a prior proceeding, which we will get into later on in this particular matter.

So we do not believe that a refund under the statutes is allowable and also continue our position that the charges are reasonable.

MS. WIEST: Just for clarification, you said

it won't be based on any filings in the gas case. Does that mean that the prefiled testimony, in particular, Mr. Hitchcock's rebuttal, is not going to be presented?

MR. MOLSTAD: Yes. It's our position that the only testimony to be considered by the Commission in making their decision is based upon testimony that is provided at this hearing. That any prefiled testimony by any party that may have been filed in the gas case docket number NG99-002 is inadmissible because this is a separate proceeding, separate and apart from the gas case.

MS. WIEST: Okay. You may call your first witness.

MR. MOLSTAD: Thank you. We would call Tom Hitchcock.

THOMAS P. HITCHCOCK,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. MOLSTAD:

Q. Would you state your name, please?

A. My name is Thomas P. Hitchcock.

Q. Mr. Hitchcock, where do you reside?

A. Huron, South Dakota.

Q. And how are you employed at this particular time?

A. I'm employed as the executive vice-president of Northwestern Energy Corporation, an affiliate of Northwestern Public Service.

Q. Would you please tell the Commission your employment history prior to the position that you currently hold?

A. I began my career with Kansas-Nebraska National Gas Company back in 1975 as an internal auditor in their Hastings, Nebraska, office. I held various positions within K-N during my 20-year career there.

I was manager of gas accounting, manager of special projects, and the last position I was in was director of rates. I was in that position for eight years.

My responsibilities were all of the state and federal filings that K-N made for the FREC and also the various state commissions.

In addition to that, I was also responsible for the consolidated accounting for the company, the filing of stockholder reports and 10-X and 10-Q's.

Q. Would you please tell the Commission what your education is post high school, please?

A. I graduated with a bachelor of science degree from Kearney State College now known as the University of Nebraska in Kearney in business administration in 1975.

Q. Have you testified in any prior regulatory proceedings?

A. Yes, I have testified in numerous proceedings before various regulatory bodies for commissions and the commissions in Kansas, Wyoming, Colorado, South Dakota, and at various rate area hearings in district court trials in Nebraska relating to rate and regulatory matters.

Q. Would you please tell the Commission what Northwestern Energy Corporation is and what your responsibilities are in your capacity with Northwestern Energy Corporation, please?

A. Yes. Northwestern Energy Corporation was incorporated during 1996 to, in a sense, be the non-regulated marketing arm of Northwestern Public Service, plus the entity that was to provide regulated services back to the utility.

The areas of responsibility that I have with Northwestern Energy include regulatory activities involving Northwestern Public Service, primarily the tariff maintenance filings, the PGA's, fuel trackers,

et cetera, including rate cases.

Another area of responsibility in the service that we provide to Northwestern Public Service is in the area of gas supply where we nominate and procure the gas supplies for the company and also go before various proceedings involving Northern Natural Gas, Northern Border and K-N and Interstate in Nebraska. K-N we're currently involved in a case there. We just had a settlement in the Northern Natural case.

But we have had the ability to utilize part of the Kansas pipeline system in Nebraska and Kansas to in effect make deliveries to Northern Natural for delivery into South Dakota, which has been a pretty good benefit for customers because it's at a cost that's lower than getting gas supplies in at certain other locations.

The other duties that we're responsible for is billing review of the customer billing system. We do this from the standpoint we want to make sure that the bills that go to customers are accurate and reflect the proper rates that are in the tariffs.

Another area that we're responsible for is market development. In the market development function we're primarily working with the large end users on the system for potential end users of gas on our system.

And I would say that we're dealing primarily with value-added agricultural businesses where we go out and work with them on their feasibility studies of connecting to the Northwestern Public Services distribution system from a standpoint of most of these entities need large amounts of gas to run their process, like an ethanol plant or a soybean plant.

I think because of these efforts over the last three years, Northwestern Public Service has seen a significant increase in the growth of throughput on its system since that which was approved in the last general rate case back in 1994. In that particular case the volume throughput was 7 1/5 BCF of throughput. And today it's nearly 10 BCF. So we've increased or helped increase volume throughput by 30 percent.

The other function that we have is the unregulated sales of gas and that's primarily providing unbundled sales service back to the historical agency customers of Northwestern Public Service. Now, when I talk about agency customers, those were large customers that were provided a contractual service.

But the gas cost that was collected from those customers was credited back to the purchased gas adjustment for other customers. There was actually a

pool of gas purchased, and any costs that we would collect from these agency customers was credited back to that cost.

Back in 1996 PAM Natural Gas expressed some concerns to the Commission that perhaps with this agency business being within the utility itself, they were unable to compete because their thinking was we could simply make a big enough discount to a potential customer, and if we happen to lose money on that deal, it would simply be paid back by the existing NPS rate payers.

So the decision was made that part of the function of this NEC group was to provide this agency sale in a non-regulated environment. We couldn't mix the cost of gas supply in with the utilities. We had to go out and acquire services specifically for Northwestern Energy.

Q. Would you explain what agency sales are, please?

A. Agency sales were sales of gas that the customer paid the embedded distribution delivery service cost of the utility, the cash-out of the sales rate, and then the company went out and was able to lock in a package of gas for individual customers. When they wanted to contract for that gas, when that

customer entered into a contract, there was a special purchase of that supply.

That supply just became one element of NPS's total regulated cost of gas. And as we collected revenues from those customers, that portion that was gas supply was credited back to the PGA. There was never any profit to be made by NPS other than the distribution delivery service portion. That was a regulated rate.

Q. You have mentioned the term PGA. Just for the record, would you explain what that term is?

A. PGA is just an abbreviation for purchased gas adjustment. Utilities like Northwestern Public Service are allowed to track the cost of gas and providing services that are not on their system. These costs are acquiring pipeline capacity on companies such as Northern Natural going out and procuring the gas commodity.

It's essentially all of the costs that are incurred prior to a distribution town border station. Those costs are put into a pool of dollars, and the customers are billed through a PGA rate component of their sales rate an estimated rate that tries to match that cost of supply.

And each month that cost that was actually

incurred is compared to the cost actually recovered in rates and any differential is trued up and reserved for a future recovery or refund back to the customer.

Q. Would you explain the difference relationship as an entity between Northwestern Energy Corporation and Northwestern Public Service?

A. Northwestern Public Service is simply a regulated utility. They provide regulated sales rates, transportation rates, that are subject to Commission approval, or in the case down in Nebraska, to the various town councils.

A non-regulated affiliate or a non-regulated entity or a third party that's marketing natural gas is free to go out and acquire capacity on interstate pipelines either through direct contract with the interstate company, through the secondary markets, which is really picking up the capacity of a party that has primary firm at usually a deeply discounted rate and then going out and lining up the gas supplies for customers, contracting with individual customers, and rebundling all those services to provide those customers a competitive rate. That the unregulated world is a very competitive arena. There is certainly a lot of people out there that want to provide services to customers.

Q. Mr. Hitchcock, what is the purpose of your testimony in today's proceeding?

A. The purpose of the testimony that I'm going to put on today is to discuss the treatment of the Nekota pipeline project as it relates to cost recovery through the Northwestern Public Service PGA.

This particular issue was determined by the parties in the base rate case proceeding to be a PGA issue and should be separated out. And certainly it was an issue that was not negotiated or settled

And the Nekota pipeline project was actually developed and completed during the year 1996. It was simply a bypass of Northern Analysis Transmission System for service to Aberdeen, South Dakota, and the company undertook this project for various reasons that I can explain later.

But the number one reason why we undertook this project was to get competitively-priced pipeline capacity to meet the needs of not only Northwestern Public Services residential and business customers, but also the agency customers of Northwestern Public Service that now were going to be provided service by either NEC or some other third party.

Q. Now, Mr. Hitchcock, then you're familiar with the events that took place leading up to the

construction of this Nekota pipeline that you have just mentioned?

A. Yes, I am.

Q. And what were some of these events that took place?

A. I think basically it started with the review that I made of the peak day conditions that occurred on February 1st, 1996, on Northwestern Public Service's system.

Q. And let me show you, Mr. Hitchcock, what has been marked as Exhibit 1.

A. Yes.

Q. Would you please -- do you know what that exhibit is? Would you please tell the Commission what that exhibit represents?

A. Yes. This is an exhibit which shows a work paper that I prepared back in early 1996 after the peak day occurred on Northwestern Public Service's system. That particular peak day occurred on February 1st, 1996.

And when I say peak day conditions, that was the day that the company required the most gas supplier throughput on its system. The information that's displayed on this exhibit shows the town border stations that Northwestern Public Service has as

delivery points on the Northern Natural contract.

The first column of numbers shows what Northwestern Public Service had contracted with Northern Natural as the primary firm MDQ, or maximum daily transportation quantity at these points. That amount totaled to 49,283 MMBtu.

The total send-out on this peak day, which averaged 25 degrees below zero Fahrenheit weather, or ninety heating degrees day deficiency, was a total send-out on the 74,179 MMBtu. We have some third party users so they were parties that had to supply their own supplies and capacity.

The net Northwestern Public Service send-out was 73,440. I simply aligned the total net NWPS usage by town border station with a firm capacity that the company had with Northern Natural.

As you can see from the information on the work sheet, the Aberdeen town border station had a contract capacity with Northern of 10,358. The Northwestern Public Service use at this point on that peak day was 19,500, so the company was 9,142 MMBtu's short of firm pipeline capacity to meet the customer requirements.

As you go down the town border stations listed there, primarily the larger towns on our system

were the towns that had had significant growth in them and were short of having primary capacity on Northern.

On the right side of the work paper I compared the send-out by type of customer, if it was a firm customer, an interruptible customer. And the analysis indicated down at the bottom right-hand corner that the deliveries to the customer meters there was a firm capacity requirement of 59,582 MMBtu. This fell well short of the contracted capacity that the company had with Northern Natural.

Now, the company was able to meet its particular needs on this day from the standpoint that it was able to acquire some secondary firm capacity in the market, and also we utilize propane peak shaving facilities on our system.

But certainly this was a serious situation where if we continued to let this happen and not have this capacity tied down as firm, there could be a potential that in the future there may not be any secondary firm available, or the propane plants don't work and we'd have to in effect curtail or shut off some firm customers. And I don't think none of our firm customers would have been -- wouldn't be happy to see that happen.

One of the events that happened during this

period around February 1st, 1996, when it was extremely cold was that it was not only cold in South Dakota, but it was cold throughout the upper Midwest, Chicago, New York, Philadelphia, and there was a huge demand for natural gas.

One of the problems that Northern Natural had is that they did not have a high enough penalty provision in their tariff to prevent customers from not putting enough gas in the system on a critical day. And the market for natural gas in the Chicago area was $20 an MMBtu. So Northern saw a lot of their gas that was to be delivered to Northern diverted to the Chicago market.

At a meeting that I had with Northern that was after this winter they said if the cold weather would have lasted a day or two longer, they would have been curtailing primary firm customers.

MR. MOLSTAD: I would offer Exhibit No. 1.

MS. WIEST: Any objection?

MS. CREMER: No.

MS. WIEST: It's admitted.

Q. So you were concerned about the availability of capacity on Northern's line to your South Dakota customers' different locations, but Aberdeen was certainly one of the main considerations; is that

correct?

A. That's correct.

Q. What other concerns did you have, Mr. Hitchcock, other than the potential lack of capacity for customers in this situation?

A. One of the primary concerns that the company had was the ability of Northern Natural Gas Company to deliver us gas when we needed it under our firm contracts.

Northern was experiencing a lot of operational problems on their system with customers coming on and off, and it caused significant problems for Northwestern Public Service primarily in the summer months when we tried to utilize our gas turbine plant at Huron to supplement our base load electric volumes.

The problem was apparent every time that Northern States Power Company fired up their Pathfinder Gas Generation Plant that was upstream of Huron. And that was a significantly larger plant and really brought down the pipeline pressures down significantly at the same time that Northwestern had to fire up their turbines because we're all part of the same map group and when loads are supposed to come on incremental power loads, everybody is turning them on at the same time. And we certainly had some operational problems

there.

I'm certainly a rate person and accountant. I don't know all the ins and outs of it, but certainly a pressure loss on a pipeline will not cause your gas to show up at another facility. It takes a huge amount of gas. And that turbine plant in Huron did take a pretty good quantity of gas when it was running.

Q. So based on this situation and concerns that you have just testified about, what did Northwestern Public Service and Northwestern Energy Corporation do?

A. Well, it was primarily up to a few of us to find a solution to the problem that we had at hand. As we identified it, we had a couple of serious problems. Number one, we didn't have enough firm capacity on a peak day to meet firm requirements on the utility.

And, secondly, some of the delivery points were not aligned properly on the existing Northern contract, which if we did hit another peak day and Northern called a point-to-point curtailment, it would cause us to be severely out of balance at certain locations.

Q. Would you explain this point-to-point, please?

A. Point-to-point would be if you took the Exhibit 1 here, and take an example of Aberdeen, the

primary firm capacity that the company had with Northern was 10,358. The actual usage on this peak day was 19,500.

If Northern would have called a point-to-point curtailment, that would have meant that you can only take on a firm basis at a particular delivery point what you have as primary firm. That would have been 10,358 at Aberdeen. All the volume above that would have been subject to the applicable Northern imbalance or overrun penalties at that time.

Since the winter of '96 here, '95-'96, we had another extremely cold winter in '96-'97. Northern took a lot of steps to really tighten up their tariff language so that there was not a lot of potential gaming on their system during peak periods.

Q. So what steps did you do then to address the situation?

A. Well, we started to look at, you know, our alternatives and options. And one of the options that we looked at was to build a bypass line to Aberdeen, South Dakota, from the Northern Border Pipeline. This would have involved bypassing Northern Natural Gas. They had a connection there already today that was serving our capacity needs. But certainly it was something that we had to take a hard look at.

To be honest with you, there was probably a few people within NPS when I brought this idea up to them, that I didn't get a warm reception. The company that I had formerly worked with provided the capacity pipeline capacity for Northwestern Public Service down in Nebraska similar to what Northern Natural does in South Dakota. Northwestern Public Service had built approximately a seven or eight-mile bypass line like this to the Trailblazer Pipeline near Kearney, Nebraska.

To be blunt, that irritated the president and CEO of K-N Interstate and told the troops go out there and steal customers. And within a matter of a couple days K-N had taken a lot of customers. They went to those customers and said, "We'll bypass Northwestern Public Service's distribution system and we'll directly connect you to K-N," and they took a significant load away from Northwestern Public Service.

There was a few people at Northwestern Public Service that did not want to get Northern Natural Gas mad at them.

Q. Just for a second, maybe for comparison purposes, how big is Northern Natural Gas compared to Northwestern Public Service as far as their system, if you know?

A. Northern Natural, of course, is -- they're an officially regulated pipeline, large capacity pipeline carrier, an interstate carrier, where they cross different state lines. Northwestern Public Service is a local distribution company and primarily serves and has investments in lines, you know, inside city limits.

But Northern provides the capacity to Northwestern Public Service. Northwestern Public Service's 49,000 MMBtu's was approximately one percent of Northern's total capacity on their system.

Q. Did you approach Northern Natural with your concerns with the capacity and pressure issues?

A. Yes. There was several meetings that were held with Northern Natural, not only addressing some of the operational considerations, but also discussing with them the fact that Northwestern Public Service needed some additional services. And that if we did buy any additional services from them, we wanted to make sure that they were competitively priced.

All of the capacity that Northwestern Public Service had acquired from Northern in the past had been at maximum ratings. And I knew there was some other LDC's that were connected, local distribution companies, connected to Northern that were in a

position that they were close to other pipelines, or other pipelines were connected to their towns and so there was more of a competitive arena.

And Northern offered other companies discounted rates. We were not in a position to go to Northern and say we'd like a discounted rate because if that's all we brought to the table, they would have said tough.

So when we had the operational meeting with them, their solution there was, "Well, as the summer load pathfinder comes on, we're sorry, but we may be able to address it, you know, at some point in the future. It's going to cost money. If you're willing to pay for it, you know, we'll do it."

That didn't really sit well with NPS management. So then we began the process of trying to negotiate to acquire additional capacity from Northern Natural. And those negotiations went on for approximately three months.

Q. When approximately did these negotiations take place? What time of the year?

A. First generally during the summer, end of May '96 through August of '96. And one of the -- I would say one of the key stumbling blocks in Northern's ability to offer us a discounted rate that would be an

attractive alternative to a pipeline was the fact that they had some favored nation language in other contracts with other customers that they had.

Q. What do you mean by favored nation clauses?

A. What I mean by favored nations clauses is that in a contract that Northern would have with another user of their capacity, if they had offered a discounted price to them and said here's your price. But if we offer that same service or a similar service at a price that's lower than this price and this contract, we will offer you that same price.

Because of our size, I mean we weren' talking about a huge load here. We were trying to at least get in that 15,000 MMBtu range and that was relatively minor for Northern. They had some contracts that were significantly more volume than that and they couldn't -- I mean if they wanted to come down, they couldn't because they would lose it, you know, lose bigger dollars on the other side.

Q. So were you able to reach an agreement with Northern to take care of this problem?

A. We weren't really able to reach any agreement, like I said, with Northern to get a discounted rate. And they knew that we were going to -- that our other option was bypass.

One of the concerns with a bypass was that Northwestern Public Service had a letter agreement with Northern that was kind of in connection with some new town expansion projects that were being looked at in the early nineties. And one of the provisions in there stated that Northwestern Public Service had to acquire all of their supply from Northern Natural for a ten-year period.

Q. I'm going to show you, Mr. Hitchcock, what's been marked as Exhibit 2. Is this the letter agreement that you have just mentioned between involving Enron, which is the parent company of Northern Natural Gas?

A. Yes, it is.

Q. And would you please -- is the provision that you just mentioned concerning Northwestern and having to take all its capacity from transportation from Northern, is that particular paragraph language in this agreement?

A. Yes. It's on page two and it's paragraph number four. It's the first sentence of that paragraph, which states that Northwestern Public Service agrees to maintain existing firm entitlement levels for a minimum of ten years and utilize Northern's system for all throughput for ten years for communities currently served by Northern.

Northern interpreted this language as something that would restrict Northwestern Public Service's ability to build and own a pipeline to bypass it. It was another -- I could characterize it as a strong arm move of Northern, the 800-pound gorilla, to give us, you know, problems.

MR. MOLSTAD: I would move Exhibit 2 into evidence, please.

MS. WIEST: Any objection?

MS. CREMER: No objection.

MS. WIEST: It's been admitted.

Q. So what did this provision number four in this letter agreement, dated November 20th, play in the continuing project of the construction of the Nekota pipeline?

A. Well, certainly we had some -- we had some bridges to cross. There was this provision that was obviously a big stumbling block to our efforts. But we also knew that we had to work with Northern in order to get the existing contracts properly aligned with delivery point capacity.

Secondly, we, Northwestern Public Service, along with every other LDC that was contracting for firm pipeline capacity on Northern, had an obligation under the federal unbundling proceeding to in a sense

take some capacity down in the field area to Kansas, Oklahoma, and Texas. You know, pay for a service that no one could really utilize.

Q. Would you please just explain field capacity just briefly, please?

A. Field capacity on Northern was really down in the areas where you had the production and you had compression in lines to gather -- in the old days Northern provided a bundled sales rate so they had all these gathering systems and spider webs of lines to in effect bring gas from the wellheads, the producing areas, up to the market area. The market area on Northern is primarily Eastern Nebraska, Iowa, Minnesota, Eastern South Dakota.

Q. Okay. And what benefit, if any, would it have been to Northwestern Public Service customers having this field capacity?

A. Having this field capacity was really of no benefit because the market had changed such that your best deals to acquire gas supplies to serve South Dakota customers was coming from Canada, off the Northern Border Pipeline. You couldn't go to a producer and add up all these field costs and get a better price. And no one else could either.

So we felt that one of the ways to increase

some additional capacity on the system was to maybe negotiate with Northern to allow us to turn back this field capacity, which had absolutely no value to us. It was a ten-year obligation that every customer had. And we wanted to get some value out of it and get some market firm. So that was one of the things that we wanted to negotiate with Northern on.

Q. So I take it you did enter into some negotiations with Northern after their initial basic refusal to address the concerns that you had for your customers; is that correct?

A. Yes.

Q. And in light of the paragraph that you just testified to, paragraph four in the letter agreement, which was an obstacle to constructing a bypass line, bypassing Northern Natural, what kind of a settlement negotiation did you end up with in that particular matter?

A. Well, we felt that Northwestern Energy Corporation, being the unregulated marketing arm, we didn't have a prior agreement with Northern, and we felt that we were in the best position to go in and negotiate on behalf of Northwestern Public Service to get the best deal for customers. We could bring to the table basically the threats that Northwestern Energy

are going to build this pipeline. We'll use it to serve customers that Northwestern Public Service has today, you know, large accounts.

So Northwestern Public Service won't be buying any capacity from you. We'll create that capacity for those customers. Northern knew that was a threat because it was already happening on their system at other locations.

And I would add right now that because what we did up in Aberdeen, the city of Watertown, although it took them a couple years to figure it out, has now built a bypass from Northern Border to Aberdeen and is effectively bypassing Northern, and those customers are enjoying obviously lower costs today too.

CHAIRMAN BURG: You mean to Watertown; right?

A. To Watertown, yeah.

Q. So you did enter into some negotiations. And if you could, just summarize the result of those negotiations in this matter.

A. Well, you know, we were going to build a pipeline. We told Northern we're going to build a pipeline.

Q. When you say "we," who is that?

A. Northwestern Energy, Nekota. Nekota was really a company that NEC created to hold the physical

assets. NEC, by our pure definition, was -- most of our stuff was to provide services to the utility and to, you know, provide other services to other customers. Any physical assets we felt that if we put them in another company it was easier to track those, you know, those costs.

And so NEC, that's why you have Nekota is the company that holds this asset. But if they wouldn't have been created, NEC was the one that was going to, you know, hold this asset. In fact, NEC was of the ones that contracted with NPS to engineer and design a pipeline to go to Aberdeen.

You know, and when we negotiated with Northern to try to get some benefits to the NPS system, the realignment of delivery point capacity, additional firm capacity, and what we felt was some other benefits.

And to get rid of this provision in this 1990 letter agreement, Northern was agreeable that if NEC gave them enough economic dollars, bought enough services from them, that they would be agreeable to enter into a contract with Northwestern Public Service that waived provision paragraph four of Exhibit 2 into the future.

It would also give Northwestern Public

Service the ability to realign its delivery point capacities and also allow Northwestern to turn back field firm for market firm that we felt was more valuable.

Q. So as I gather then, the purpose of your negotiations in this matter was to come up with a solution that would be in the best interests of Northwestern Public Service's customers; is that correct?

A. Yes.

Q. Mr. Hitchcock, have you put together a summary sheet of the Nekota pipeline project with its costs benefits?

A. Yes, I have.

Q. I want to show you what's been marked as Exhibit No. 3. Could you identify that, please, for the record?

A. Yes. This is a summary of the project costs for the Nekota pipeline, the cost responsibility, and I have listed several of the project benefits.

Q. Mr. Hitchcock, at this particular time I would like to have you explain and go over this Exhibit No. 3, the summary of the Nekota pipeline. Would you please explain the cost portion of this particular item maybe starting with the project cost and we'll work our

way down, please?

A. Okay. The first item that I have listed there and obviously it's the largest cost item, is the capacity cost from Northern Natural for some firm transportation and firm delivery services that NEC had to take on in order for Northern to be agreeable to change some contractual terms in contracts that it had with Northwestern Public Service.

The costs there -- we also got to the firm transportation with the costs. It wasn't as if the project didn't get some additional capacity and value also. But anyway that's the largest component of this project to bring capacity to the NPS system.

The second item there is the pre-tax return on the Aberdeen pipeline. That simply the result of taking the revenues that we have allocated to both NEC and NCS and subtracting out the other cost. This is kind of the fallout. And on an after tax basis the -- and utilizing NPS's capital structure that was in its 1994 rate case, this produced a 12.34 percent return on equity.

The third line there, property taxes is simply the actual property taxes that were assessed Nekota on this pipeline during 1998, and those costs were paid in '99.

Then the last item of cost there was the administrative cost per regulatory review balancing nominating and procuring gas supply off Northern Border for both Northwestern Public Service and NEC's customers in Aberdeen.

Q. So the cost then of $824,000, those are costs that were -- I'm going to call them kind of a trade-off cost, so to speak, in order for the pipeline to be built. Would that be a fair statement?

A. I would say it was a trade-off for NPS to be able to utilize another source of supply rather than using Northern and also to take care of some other contractual commitments that NPS had made, primarily realignment and so forth that needed to be fixed. So all of these costs were value that was placed on this whole project.

I mean the project at the beginning was we need additional firm capacity. How we got it, you know, negotiate for it, build a bypass. I mean these were the project costs.

Q. And this project was based upon the determination that it was in the customers' economic interest to pursue the construction of a pipeline versus the continued -- continuing the situation and the costs that would have been paid to Northern

Natural; is that correct?

A. That's correct.

Q. Moving on down to the cost responsibility portion of this Exhibit No. 3, could you please explain that portion of the exhibit, Mr. Hitchcock?

A. Okay. There's really two entities that were using the pipeline capacity to serve customers, Northwestern Public Service and Northwestern Energy. Northwestern Public Service's needs were to serve residential and business customers.

Northwestern Energy's needs was to have some capacity available to serve the existing agency accounts of NPS in an unregulated market. We looked at the pipeline capacities and in general what each company would utilize and determined basically a transfer rate of $3.20 and wanted that rate to be sufficient enough to cover all the costs that were incurred in this project and to make sure that that cost was very competitive with what the alternative would be.

The Northwestern Public Service portion of that cost responsibility $576,000, or 70 percent of the cost, was determined based upon their use of the Aberdeen pipeline up to 15,000 MMBtu day of firm service.

The contract that NEC had with NPS, however, allowed NPS that if they needed additional capacity on any particular day, that the charge for that would be 100 percent load factor firm rate, which would have been a very minimal charge, around 10 cents an MMBtu.

Q. How would that compare, Mr. Hitchcock, to this scenario under Northern Natural if Northwestern Public Service would have wanted more than $15,000 allocation of firm capacity, what would the costs have been under the old situation with Northern Natural?

A. I think you're referring to 15,000 MMBtu rather than dollars?

Q. Yes.

A. But generally, under Northern Natural, if you needed firm capacity you contracted for that capacity 365 days a year.

Q. And with the arrangement you put together here, what would be the cost difference between Northern Natural and working with NEC?

A. Compared to the average cost that Northwestern Public Service was paying for its existing 49,000 a day of capacity from Northern, that cost came in in an average of $6.65 per MMBtu. If you simply multiply that times 15,000 times 12 months, that would have been an annual cost of approximately a 1,200,000,

or twice what the solution that NEC came up with.

Q. This $576,000 of cost that you show allocated to Northwestern Public Service, is that the dollar amount that is at issue here in the purchased gas adjustment?

A. Yes, it is, because as Northwestern Public Service receives that cost assignment, those costs are booked on a monthly basis to the purchased gas account.

Q. I would like to then move on to the last portion of Exhibit No. 3, Mr. Hitchcock, and that's the project benefits. Could you please elaborate and explain the benefits listed there?

A. Yes. Probably the key benefit was removing the restriction in Northern's contract with NPS that required Northwestern Public Service to exclusively use Northern's system for its supply. Getting rid of that restriction was certainly a benefit to Northwestern Public Service's customers and the customers of NEC.

The second item there is the peak day pipeline capacity. As I had shown on Exhibit 1, there was certainly a need to acquire additional firm pipeline capacity to serve the various town border stations of Northwestern Public Service.

Again, acquiring peak day capacity was a benefit to Northwestern Public Service and NEC's

customers. Reliability, pressures at Aberdeen on certain days, the Huron turbine plant had needs, was certainly a benefit to both NPS and NEC.

When we come down to reassignment of the delivery point capacity, that was not an issue with NEC because we didn't have a contract with NNG at that time. That was Northwestern Public Service's issue that we had to resolve. And resolving that issue and allowing Northern allowing the realignment there was a benefit to NPS customers.

Q. How does that benefit -- how did that benefit NPS's customers?

A. If they wouldn't have allowed Northwestern Public Service to realign those delivery point capacities, if there would have been another future peak day condition and Northern imposed restrictive point-to-point deliveries, we would have had certain towns on our system that would have had firm capacity requirements over and above what we had contracted with Northern, and certainly there could have been some substantial penalties incurred because of that.

The other item number five -- and this has really been a tremendous benefit to NWPS customers, the field capacity turn-back and conversion to market firm service.

Back in 1996 when we first started looking at this, NPS only had 49,283 of firm market capacity. And effective this November, November 1, 1999, NPS will have in excess of 56,000 of market area capacity from Northern. And it hasn't cost a dime to acquire that additional 7,000 MMBtu. It was just a shift of what NPS was paying for firm capacity that they couldn't use to market capacity, that they could either use or release in the market and get some value for it.

Q. So explain what is the specific benefit of this additional throughput.

A. Well, the benefit of this additional capacity is that NPS would not have to go out and acquire additional firm capacities as the system -- as their system grows. And also if it's such that Northwestern Public Service isn't needing that capacity on certain days like today, they have more capacity to release into the market, get some value for it, and credit that back to customers through the purchased gas adjustment.

And I guess that leads into item number six there, release capacity credits. Because this project created capacity, Northwestern Public Service was able to have more excess capacity on non-peak days to sell into the market. And this was an extremely good

benefit for NPS customers because any capacity revenues that were received are credited back to the PGA.

And item seven there, ability to maintain interruptible loads on peak days, is a benefit for all customers because customers don't want to necessarily have the additional burden of cost of switching every time it gets 20 degrees or 10 degrees on Northern's system.

They like the ability to be able to flow that gas on as many days as they can. And it's a good benefit that for the utility that they can maintain their margins that they have designed their rates on in rate cases.

Q. Are there any other benefits on NPS's peak day in Aberdeen that were the result of this particular Nekota project?

A. I think the additional benefit there is that not only do we have a pipeline up there that is capable of a future delivery of 24,000 MMBtu a day, but that Northwestern Public Service is still connected to Northern Natural Gas.

And if there were some reason that service was interrupted on Northern Border, we would probably be able to, you know, make a switch to Northern Natural. Having two pipelines to a TBS is a tremendous

advantage.

Q. So if I understand this Exhibit No. 3 then, as a result of this Nekota pipeline project, the costs -- I should say the charges to the customer through the purchased gas adjustment were roughly one-half of those that would have been charged on the Northern Natural Gas scenario part of the project, plus these additional benefits from the project were credited to Northwestern Public Service customers; is that correct?

A. That's correct.

MR. MOLSTAD: I would offer Exhibit No. 3.

MS. WIEST: Any objection?

MS. CREMER: No objection.

MS. WIEST: Admitted.

Q. Mr. Hitchcock, I believe that you just mentioned here as you were talking about Exhibit No. 3, the ability for released capacity credits; is that correct?

A. That's correct.

Q. I want to show you what has been marked as Exhibit 4. Would you please identify that exhibit, please?

A. This is an exhibit that demonstrates the capacity release credits that Northwestern Public Service had one year before the Aberdeen pipeline was

put into place and the one year after the Aberdeen pipeline was put in place.

During that period an additional $200,000 was generated over and above what was in place the year prior.

I need to note a few things about that. The November '96 through March '97 time period, I think as everybody remembers, was an extremely cold winter. That's when we had a lot of lot of snow and wind and cold days. And for that winter period it was one that even the natives were wanting to move out of the state.

Because we had that cold weather there was essentially more of a demand for pipeline capacity on Northern's system, and Northwestern Public Service was able to provide that.

If you look at the last two winters, we've had pretty mild weather, and so the demand for capacity has softened a little bit, but our capacity release credits are still running well over $200,000 a year.

Q. Would you explain to the Commission how these capacity release credits benefit Northwestern Public Service customers?

A. As NPS contracts with Northern for firm capacity on their pipeline, they pay a fee. If that

capacity is not needed by customers of Northwestern Public Service, then Northwestern Public Service tries to sell that capacity into the market for some value, get some of their dollars, you know, recovered.

As that is done, these dollars that are received for this released capacity is credited back to the capacity cost through the PGA and that's a benefit for customers that it lowers their gas cost.

Q. So this would in effect then lower gas cost to customers; is that correct?

A. Yes.

MR. MOLSTAD: I would offer Exhibit No. 4.

MS. WIEST: Any objection?

MS. CREMER: No objection.

MS. WIEST: Admitted.

Q. Mr. Hitchcock, under the Nekota pipeline arrangement is Northwestern Public Service limited to the 15,000 MMBtu's of capacity on the Aberdeen pipeline?

A. No. They have the ability to take all of their, you know, the entire capacity of the pipeline on any day they need it. In fact, they have a higher priority right to that capacity than NEC's customers.

Q. And could you explain what difference in costs, if any, there would be to NPS to take additional

firm capacity over the 15,000 MMBtu's? Under the current arrangement with Nekota what would have been the result to Northwestern Public Service under the Northern Natural Gas scenario?

A. If NPS, as an example, needed 20,000 a day at Aberdeen, rather than, you know, 15, that additional five would have been charged out at a rate of around -- at a cost of around $500, 10 cents an MMBtu for just that one day. And we didn't have any days in '98 that they exceeded 15,000 because of mild weather.

If that same condition would have happened on Northern Natural, you would have had to have acquired capacity at a much higher rate. In fact, Northern's -- just their interruptible overrun rate is 45 cents in the winter, which is four and a half times, you know, the Nekota charge.

But more than like physical, that was an ongoing condition and you had to have that firm capacity for, you know, into the future, you would have had to lined up capacity with Northern at a very high rate in the winter for five months or a 12-month service, but it would have cost substantially more than this incremental fee.

Q. Mr. Hitchcock, have the $576,000 of costs that we've been talking about here for the

Nekota/Aberdeen pipeline project, have they been promoted as a purchased gas adjustment item before previously?

A. Yes, those -- that cost has been included on our monthly purchased gas adjustment filings that are given to the Commission on a monthly basis. The value the 576,000 has remained the same value since day one.

Q. Has this particular Aberdeen pipeline project been part of any prior docket items before this Commission?

A. Yes. It was part of the gas cost that was included in the earlier docket that I was discussing, when we had the filing back in 1996 to address some of PAM Natural Gas's concerns with our PGA and with our rates in general.

We made a filing in the summer of 1996 and there was a proceeding and rates were adjusted and a new purchased gas proposal was put in front of the Commission that instead of just adjustments to the amount that was reflected in base rates, we, in effect, took all the gas costs out of base rates and had a now stand-alone calculation for those.

Q. I want to show you, Mr. Hitchcock, what has been marked as Exhibit No. 5. Would this be the information that you have just mentioned as far as the

docket item?

A. Yes, it is.

Q. And would you explain to the Commission just exactly what is contained in that particular docket item?

A. This was the Northwestern Public Service's response to a staff data request that was involved in Docket NG96-015. Part of that data request -- and you would have to go back, it's staff number ten.

Because we were changing the way we were showing how our purchased gas filings would be made in the future, we were to provide a sample PGA filing incorporating the effects of the filing with all supporting work papers.

Our response was attached as Exhibit C. If you go back to Exhibit C, there's numerous pages there that set forth the format as we proposed for how we would show gas cost in future PGA filings.

Of particular note on that the second page, which I think it's the second page there of Exhibit C, we have laid out the demand cost that NPS was incurring at that particular time, both charges on Northern Natural and any release credits that we had, plus the Aberdeen pipeline connection to Northern Border. That that 15,000 MMBtu per day at 3.20 rate for 12 months

was $576,000.

We worked pretty closely with the staff on making sure that they were comfortable with the new format of our PGA layout here. There was numerous discussions back and forth. I can't tell you each and every discussion that was held, but certainly this format was looked at by staff and basically approved because it's format that we utilize today in current PGA filings.

The costs that were developed here were the costs that supported the purchased gas tariff sheet that was approved in this filing.

MR. MOLSTAD: I would offer Exhibit 5.

MS. WIEST: Objection?

MS. CREMER: No.

MS. WIEST: Admitted.

Q. I believe, Mr. Hitchcock, you testified that there was an order that followed this particular case; is that correct?

A. Yes, there was an order entered into by the Commission at an ad hoc meeting on November 12, 1996, that approved the tariff sheets. There was numerous revisions. We were doing our transportation changes and purchased gas layouts and a lot of other matters, but these rates were approved and were approved to be

implemented on December 1st, 1996.

Q. As I understand your testimony then, the Nekota pipeline portion of those charges and those tariffs that were approved were part of Exhibit 5; is that correct?

A. That's correct.

Q. Okay. And those tariffs then that were approved by this order were based upon the materials presented in your data response; is that correct?

A. Right.

Q. I want to show you, Mr. Hitchcock, what's been marked as Exhibit 6.

MS. CREMER: At this point I just want to interrupt. In my Exhibit 5 there's two Exhibit C's. One is right behind the testimony and then -- but they're not the same, so I don't know if you want to straighten that out.

MS. CREMER: Right behind the testimony I have -- right behind the testimony I have an Exhibit C, the first page of which says the Demand of Cost Recovery. Then my other Exhibit C, which is at the end of the document, the first page is called Reconciliation of Rate Changes and Effects on Revenues.

MS. WIEST: I have a second Exhibit C at the very end of the document.

A. It's the first Exhibit C.

MS. CREMER: It's going to make for a confusing record.

MS. WIEST: Should this be a different exhibit number? What is this last exhibit?

MR. MOLSTAD: The last exhibit is five.

MS. WIEST: There are two Exhibit C's. Do you want the last Exhibit C to be a different one?

A. I think it's going to be F.

MS. CREMER: I think you need to go through the whole thing and sort it out. They're not extra, they're different. I don't know which Exhibit C they were talking about when they were talking about it before, so I'm not sure.

A. I think it was the whole response, you know, to the data request.

Q. (By Mr. Molstad) Yeah. So contained in Exhibit 5 then is the entire response to the data request; is that true, Mr. Hitchcock?

A. Yes.

Q. And then specifically you know, would you indicate which Exhibit C that you were talking about referred to that we have just testified to concerning this particular matter so we can mark that and include that specifically for the record?

A. It would have been the first Exhibit C in the packet, which consists of five pages, which is the layout of the purchased gas adjustment work paper filing.

Q. So for the record, then, the Exhibit C you were referring to in your testimony is the exhibit which consists of five pages with a title page before that that says Exhibit C, that is right before the Exhibit D; is that correct?

A. Yes.

MR. MOLSTAD: Does that help everybody there?

CHAIRMAN BURG: The only thing I'm wondering, what do we do with the other B and C? Take them out or classify them as a different one? Or what do you do with them?

MR. DIETRICH: This is all part of one exhibit really that was to show the full response that was provided in that rate matter. The pertinent line that we're talking about is in the first part of it, but we didn't want to give a portion of a filing that was made. We decided to give the whole thing. If you read through the text that follows, it speaks to Exhibits B and C, and those exhibits were for other information that was filed. They were supporting

data.

So I think the point to focus on is the first point, but I think there's no harm in offering the whole exhibit to show the breadth of information that was provided in that docket.

CHAIRMAN BURG: The only thing is I'd like to see these classified as F and G or something.

MR. DIETRICH: Certainly, except the references in the text then will be erroneous.

CHAIRMAN BURG: There are references to these B and C?

MR. DIETRICH: There are references in the text to that B and C in the text of this whole document.

COMMISSIONER SCHOENFELDER: I think it's perfectly okay because he already said which Exhibit C he's referring to in his testimony here. I think that's clear enough.

MS. WIEST: We're leaving it as it is.

Q. Okay. Showing you Exhibit 6, Mr. Hitchcock, what does that particular exhibit show?

A. That that's the copy of the order in NG96-015 that I had previously talked about.

Q. And, again, what did that order do and how did it relate to the Nekota/Aberdeen pipeline project?

A. The Nekota costs that were assigned to NPS were included on the proposed and approved work papers for purchased gas adjustment true-up accounting, and those costs were incorporated into the tariff rates that were approved by the Commission to be effective December 1, 1996.

MR. MOLSTAD: I would offer Exhibit 6.

MS. WIEST: Objection?

MS. CREMER: Well, it's an order by the Commission. It speaks for itself. But, yeah, I have no objection.

MS. WIEST: Admitted.

Q. Mr. Hitchcock, since the order was entered in Exhibit 6, have the costs for the Nekota pipeline been submitted to the Commission for their approval since that time?

A. Yes, it's been the same cost and same line identification through our latest PGA that we filed this month.

Q. Would you explain to the Commission just how you submit a purchased gas adjustment filing, what that process consists of?

A. Well, it consists of looking at what our current demand costs are for a 12-month period and what the current commodity cost of purchasing gas are,

putting all those costs in the work paper to derive a rate that we would to have to charge the various customer classes for in order to recover, you know, our gas cost.

Q. And those are submitted to the Commission staff for their review?

A. They're submitted on a monthly basis right at the first of the month.

Q. And Northwestern Public Service has been submitting this same $4.50 rate on a monthly basis for how long?

A. Since this December of '96 rate.

Q. And have there been any objection to that filing?

A. I don't recall any that I recall on any cost in those three years.

Q. Mr. Hitchcock, what is the company's recommendation regarding the continuation of the $576,000 cost for the Nekota pipeline and/or Aberdeen pipeline as part of the purchased gas adjustment clause for Northwestern Public Service?

A. Well, it's our recommendation that the Commission approve the inclusion of that $576,000 in the purchased gas adjustment clause and that we need to recognize that this is a creative way of getting value

for customers. And I think that all customers on Northwestern Public Service's system have benefitted from this solution.

MR. MOLSTAD: I have no further questions.

MS. WIEST: Thank you. Let's go off the record.

(A DISCUSSION WAS HELD OFF THE RECORD.)

MS. WIEST: I think we might as well stop now. We'll be back at 1:30.

(AT THIS TIME THE NOON RECESS WAS TAKEN.)

MS. WIEST: Let's go back on the record. Ms. Cremer, do you have any questions?

MS. CREMER: Thank you.

CROSS-EXAMINATION

BY MS. CREMER:

Q. Good afternoon, Mr. Hitchcock.

A. Good afternoon.

Q. Could you explain the organizational makeup of all these companies for me, please?

MR. MOLSTAD: What do you mean by all these companies, Counsel?

Q. Could you explain the organizational makeup for me? I mean we can do it this way: At the top is Northwestern Corporation; right?

A. Right.

Q. That would be the parent company?

A. Yes.

Q. And then you testified before as to the relationship between NWPS and Northwestern Corporation and you said that was a division; is that correct?

A. I don't know if I testified to NPS was a division of Northwestern Corporation, but it is.

Q. Okay. And what's the difference between a division and an affiliate?

A. A division is within the same corporate entity. They share the same employer identification number and so forth. And an affiliate has a separate set of books and records.

Q. And what is the relationship between Northwestern Energy Corporation to Northwestern Corporation?

A. Northwestern Energy Corporation is a subsidiary.

Q. What is the relationship of Nekota to NEC?

A. NEC -- Nekota is a direct subsidiary of NEC. So it would go corporation, Northwestern Energy Corporation, Nekota.

Q. I'll hand you what's been marked as Exhibit D. Is that an exhibit that we received from -- that staff received from your company?

A. Yes, I believe it is.

Q. Does that accurately depict the scenario that you just laid out for me?

A. Yes.

MR. MOLSTAD: Counsel, is this Exhibit D, is that what this is?

MS. CREMER: Yes. I would move for the admission of Exhibit D now. I don't know if Rusty has had a chance to look at it yet.

MS. WIEST: Is there any objection?

MR. MOLSTAD: No objection.

MS. WIEST: It's been admitted, Staff Exhibit D?

MS. CREMER: D as in David.

Q. Nekota's original investment in the pipeline was $1,185,000; isn't that correct?

A. Yes.

Q. In your data response 8-07, which I don't know if you have that with you or not, but if you disagree with me, we can pull it out. You stated that Nekota's utility type revenue requirement would be $229,300, which includes a $48,000 management fee; is that correct?

A. Yes, I believe so.

Q. NWPS is paying $576,000 for a 62.5 percent of

Nekota's capacity; is that correct also?

A. No.

Q. Where is that wrong?

A. That's wrong.

Q. Why is it wrong?

A. They're paying for the entire capacity of the Aberdeen pipeline. They have the use of that entire pipeline.

Q. Out of the 24,000, isn't it correct that the pipeline has a physical capacity of 24,000 MMBtu's?

A. Yes.

Q. And I thought they were using 15,000 of those?

A. They are. The $576,000 that's assigned is based on 15,000. Anything above the 15,000 is theirs but they pay it just on the days day they need it.

Q. For how many years will the $576,000 cost be passed on to the rate payers?

A. In theory, the next seven years because that's the length of the term of the initial contract that's remaining. It's a ten-year contract.

Q. So what's the total amount rate payers are going to pay for this $1,185,000 pipeline?

A. The Northwestern Public Service rate payers are going to pay approximately -- if you look at the

project, 70 percent of the cost of that pipeline, the cost of service of that pipeline. Which is what?

Q. Which is what number? What's the amount?

A. You said that was eight seven?

Q. 8-07.

A. I guess the best way to do it is to look at my exhibit. I think it's exhibit -- I believe it was three?

Q. I don't see a figure on there that shows after, I believe you said at least ten more years, how much the total amount rate payers are going to be paying.

A. Northwestern Public Service rate payers will pay the 576,000.

Q. For ten years?

A. For ten years.

Q. Who is a management level employee of Nekota?

A. Rod Leyendecker, Curt Pohl. I'm not.

Q. Is that it?

A. I guess I don't have all the management team list in front of me. Those would be the primary individuals.

Q. Okay. Are any of those -- are either Rod or Curt also employed by NWPS or NEC?

A. Curt is employed by NPS and Rod is an

employee of NEC.

Q. Earlier you testified that -- and I'm paraphrasing here, but that NNG, Northern Natural, was unwilling to change or discount its transportation charges. Do you recall that?

A. Yes.

Q. Did NWPS ever discuss litigating this issue or challenging the legality of this letter?

A. Yes, that was certainly discussed at NPS.

Q. And why was that not pursued?

A. I think that that wasn't pursued from the standpoint that once we approached Northern with that, that they began to -- we were starting to make some points with them and they felt that -- they didn't want to go -- they didn't want to become a part of a lawsuit, neither did Northwestern want to be become part of a lawsuit. So after that we just negotiated the -- NPS negotiated the best deal it could for customers.

Q. Earlier you had said that in talking about those discount rates, did I understand you correctly you never actually asked Northern Natural for discounted rates, you just assumed it would be rejected?

A. Oh, no, we asked them for a discounted rate.

Q. Wouldn't it have been a prudent business move on NWPS's part to explore the course of having another contractor build the pipeline and then use that information to Northern Natural as to why it would be in your best interest to have litigated this matter?

A. I don't believe that was considered here from the standpoint that a pipeline built by someone else -- we have very capable people at NPS to engineer and design pipes and go out and acquire a contractor to build a pipe at a reasonable cost.

Q. Did this cost that was being passed on to the rate payers not really matter to NWPS because it was simply going to be passed on so the cost was irrelevant?

A. No.

Q. Your testimony -- or you talked about the benefits in your testimony. I think maybe it shows up on the bottom of Exhibit 3. Can you quantify those benefits?

A. Quantify them in what manner?

Q. Put a dollar figure on it.

A. Dollar figure? Well, I would say the first one, which is to remove the restriction of exclusive NNG supply for NPS customers being short $10,000 a day firm, they would have had to have acquired additional

capacity from Northern since they were the only pipeline provider.

And if we went on the historical cost of what our existing capacity cost, that would have been an annual cost of $1,197,000. It's stated right above that, that benefit. And that would have been just the amount of capacity that would have been needed at that time to meet the needs of the Northwestern Public Service system without any future growth.

Q. Okay. What about the rest of them?

A. Peak day pipeline capacity, again, that falls in with removing the restriction of the exclusive supply. If we would have to get additional pipe -- we got -- we created additional pipeline capacity with this Nekota pipeline. Had we not created additional capacity, there would have been cost to Northern to purchase that capacity.

The reliability, the pressure at Aberdeen, again, it was a pressure problem on their whole branch line from Sioux Falls that when the generation plant went on line, Northern States Power that brought down the pressure and inhibited Northwestern Public Service's ability to run its Huron turbine plant.

Now, that certainly wasn't -- that wasn't a detriment to gas customers, but it was a costly thing

to electric customers if we weren't able to power that unit up. We could have faced severe penalties from the power pool.

Q. But did you?

A. But did we?

Q. Yeah.

A. No. Reassignment of delivery point capacity, again, if we wouldn't have realigned those and Northern called a point-to-point delivery, there would have been additional cost to NPS for not having enough primary capacity at certain delivery points.

And in order to solve that problem they would have had to entered into a contract with Northern to get additional capacity at those points.

And the amount of that shortfall could have made up the, you know, ten or 15,000 that they were short on the system. Certainly if we went out and acquired capacity that we were short, we would have put it at those points.

So, again, that's a part of the cost from Northern. It would be the million two.

Q. Was that all of them?

A. The field capacity turn-back issue is such that Northwestern Public Service is paying for field capacity that they couldn't utilize. There was other

customers that had this obligation from Northern that they couldn't utilize this capacity.

We have now put in place in the contract with Northern and NPS the ability for Northwestern Public Service to turn back 10 percent of that TFF volume commitment on an annual basis and convert it to market firm.

There is no cost, additional cost to Northwestern Public Service because of that but certainly we now have over $7,000 -- or 7,000 MMBtu's of additional firm capacity on the market area on Northern that NPS can use for customers' needs o· to release in the open market.

The release capacity credits every year since the pipeline has been in place, the cumulative 12-month credits have been larger than the credits prior to the pipeline going into service. The ability to maintain interruptible loads, Northwestern has not interrupted any loads on their system the last couple years.

The major reason there is it hasn't been extremely cold. It's been mild winters. But even had we had some fairly harsh weather, we would still be able to keep a majority of those loads on. And so that has the benefit of Northwestern Public Service retaining those distribution margins.

Q. Are the benefits you discussed dependent on who owns the pipeline?

A. The benefits would -- are not dependent upon who owns the pipeline as long as you take into consideration all of the costs that were set forth and negotiated with Northern to be able to derive those benefits from this deal.

Q. Wouldn't the rate payer be better off with a rate being assessed that declines with time as opposed to a flat fee that remains consistent for at least ten, if not 20 years?

A. I believe a rate payer is better off having a fixed known cost for the next ten years than be subject to an interstate pipeline increasing their rates through gas rate cases.

Q. Has NWPS ever released capacity on the Nekota pipeline to anyone else?

A. No.

Q. Do you have any plans to release to anyone else?

A. Really the excess gas that's available on that pipeline is utilized by NEC and NPS doesn't utilize it. And, no, we don't have any intentions to let third parties use it.

Q. Do you know does NEC plan to release to

anyone else?

A. We really don't have any capacity to release. All we're doing is buying it on 100 percent load factor basis of what capacity we need on a daily basis from Nekota.

Q. Was staff ever notified directly of this pipeline being built?

A. What do you mean directly? Like a letter?

Q. A letter, phone call?

A. No, no.

Q. Was the pipeline safety inspector ever notified?

A. You would have to ask somebody in operations.

Q. Who would that be?

A. Umm, Curt Pohl perhaps. He would have been the operations person.

Q. Would you disagree with me if I tell you the pipeline safety inspector was never informed?

A. I don't know.

Q. Would you know why he -- why, if you accept my argument as true, that we weren't informed? Do you have any idea why that would have been?

A. No.

Q. When was it decided to build the pipeline?

A. Right around the first part of August of

1996.

Q. And who designed and built the pipeline?

A. That pipeline NEC contracted with NPS to design and construct the pipeline. And, to my knowledge, they used Distribution Construction Company to do the physical construction. NPS just oversaw the project.

Q. When was the pipeline completed?

A. In late October, early November of '96. I think it was actually completed prior to November 1, and we still had to get the tap connected with Northern Border.

Q. And then this pipeline connected the Northern Border pipeline with NWPS's existing pipeline in Aberdeen; is that correct?

A. Yes, that's correct.

Q. Who actually owns the pipeline right now?

A. Nekota Resources.

Q. Did you seek any other bids on the pipeline?

A. You mean NEC?

Q. Yeah. Did NEC seek out any other bids?

A. No.

Q. Why not?

A. NEC is a non-regulated company, and we looked at the value of what that pipeline would cost and were

somewhat familiar with what other systems cost per mile or per inch of pipe, and it seemed like a very reasonable rate. We've had a good history with the company that was going to do the construction, very reasonable cost so...

Q. Who's the pipeline operator?

A. The pipeline operator is Nekota.

Q. Would that answer be different after the first five years?

A. No.

Q. Okay. Now, total firm capacity is 24,000 MMBtu's per day; correct?

A. Correct.

Q. And of that NEC purchases 15,000 MMBtu's and then resells it to NWPS for a monthly rate?

A. Right.

Q. Of 3.20?

A. Right.

Q. Is NWPS buying supply from NEC also and then marking it up?

A. No.

Q. Do you have Exhibit 5 in front of you?

A. Yes, I have it.

Q. Okay. On that forty-page exhibit I want you to show me where the Nekota pipeline charge shows up.

A. Under the first Exhibit C, second page, it's about two-thirds of the way down there, it's got a line description of NBPL to Aberdeen, capacity 15,000, 3.20 a day, 576, 576,000.

Q. Looks like pretty much everyone has found it. Now, unless specifically pointed out -- and I believe you told us before this was the first time this showed up and it's on a whole new PGA tariff. It's completely different than what has been filed in the past. And unless that is specifically pointed out, it would not be possible to know that that was a transaction with an affiliate; correct?

A. Not looking at that and not knowing what the affiliates were, no.

Q. Right. And hasn't there always been a Northern Border pipeline, which is what that NBPL stands for, Northern Border Pipeline serving Aberdeen, or since 1979 I'll say?

A. No, there's never been a -- Northern Border doesn't serve Aberdeen.

Q. Who does?

A. Northern Natural.

Q. Has the PGA ever said Nekota or NEC or has it always been labeled NBPL?

A. It's been labeled this way.

Q. Right from December '96 through last month's filing; isn't that correct?

A. Yes, that's correct. And I would also note that the other fees there, the SMS reservation fee, the TF-12 base, the TF-variable, the TF-5 variable, isn't labeled with any name of who provides that service either.

Q. Who did you talk to on staff about this? Earlier you had testified that you talked to staff, showed it to him, spoke with detail to them. Who did you talk to?

A. This exhibit was a staff data request. And after this information was provided, Dave Jacobson talked to me and talked to Jeff Decker about a lot of the line items and information that was on this exhibit.

Q. And he specifically talked to you about the $576,000?

A. I don't know that he specifically talked to me about the 576.

Q. You don't know or you don't recall?

A. I don't recall, I don't recall.

Q. Or he didn't? Did you point out this to him?

A. I don't recall.

Q. Look at Exhibit 4.

A. Okay.

Q. Looking at that exhibit, when was the pipeline placed in operation?

A. November '96.

Q. It says at the top right-hand corner?

A. Or left, depending on what hand you use.

Q. Can you explain why the capacity dollars release jumped in June of 1996?

A. No, not specifically.

Q. What were the volumes released for Exhibit 4?

A. I do not know.

Q. Wouldn't we need to know the volumes when we talk about capacity?

A. I think what's important is the total value that is received for that capacity and you can certainly release very little bit of capacity in the winter and get an extremely good rate for it because people need it.

And then on the other hand, in the summer we probably have like everybody else does a lot of capacity that we can't even sell on the release market. It gets a very low rate.

Q. Could you provide that information for us in a late-filed exhibit?

A. The information would be available in our

books and records.

Q. Okay. And would you be willing to provide that as a late-filed exhibit?

A. Yes.

Q. Why was there more capacity released before the pipeline was operational than after?

A. I don't believe there was more capacity released before the pipeline went in operation. There was more released after the pipeline went in operation.

Q. Maybe I don't know how to read Exhibit 4 then, the left side here. It would appear that the fall of '97 when compared to -- well, go June, '97, June '96. And the release capacity credits and the release or capacity release benefits. It appears that out of the last five, four of those are negative.

A. Yes.

Q. So doesn't that indicate that more capacity was being released before the pipeline was operational than after?

A. Perhaps in certain months depending upon the summer weather. I mean we've had ability to release more capacity in the summer when there's generation needs.

And unless I know what the weather was like in the summers, if there was value there or somebody

needed it, individual months can be different year to year. Just like the capacity that we would have sold in November of '97 and November of '98, especially last year, I mean it was warm, no one wanted it.

And that's why you look at it in a 12-month rolling average because depending upon the market within an individual month and the demand, you don't know if you have capacity release, and if you do, what value you're going to get for it.

Q. So then I guess what you're telling me is we can't really tell what effect the pipeline has with this exhibit, can we?

A. No, I don't think you can say that. I think that clearly we didn't have extra capacity to move in the wintertime a Northwestern Public Service's system. In the past there was very few credits for capacity release because NPS needed on almost every day its full entitlement from Northern.

Because the pipeline at Aberdeen was built, the best value for that capacity is created in the wintertime when there's more of a demand for pipeline capacity. Pipelines are built to meet peak day loads, not loads in the spring or the fall or the summer.

Q. Why did Northern Natural get rid of the restriction after the competitive threat of the Nekota

pipeline was built?

A. Because NEC threw $588,000 of value to them.

Q. Let's talk about that value. Look at Exhibit 3, please. Under project costs you list that $588,000. Why is this cost allocated as an expense solely to Nekota when the benefit goes to the entire system?

A. The expense is really not allocated to Nekota. The expense is allocated to this particular project of getting capacity on Northern Natural. In order to utilize a bypass pipeline, number one, NPS had to get that restriction out of that contract with Northern.

Now, it can certainly be argued if we litigated it would we have won? Hard to tell. If Northern would have litigated, would they have won? The fact remains it wasn't litigated. There was other NPS needed capacity, firm capacity, a minimum 10,000 a day to meet peak day conditions. And they had realignment problems where their capacity was on delivery points at TBS's was not aligned with what their peak day was.

And in order for Northern to agree to let NPS or, you know, use a pipeline that was either by an affiliate or someone else, they needed economic dollars

or a buy-out of that contract for some consideration of value.

And so unfortunately that was a project cost. It would have certainly been nice if the capacity on NPS's contract would have been in line and we would have had adequate capacity. We probably wouldn't have been looking at a pipeline project anyway because we wouldn't have needed additional capacity.

But sometimes when you look at projects it's difficult to just isolate to one item of that project because you have to consider there could potentially be other costs in order to make that venture work. That 588,000 was, you know, buy-out dollars or whatever you want to call it, in order for NPS to use another pipeline rather than Northern.

Q. So was this $588,000 something that was actually paid by Nekota?

A. No, it's paid by NEC on a monthly basis.

Q. Who actually benefits from the capacity?

A. Northwestern Public Service and NEC.

Q. What sort of basis or support do you have for 588,000, and do you have some sort of work papers?

A. Yes.

Q. What are those based on?

A. The books and records from NEC. That was

provided as an exhibit to my rebuttal testimony, Exhibit TPH-4.

Q. But that's not in evidence so we're not going to -- we can't talk about it.

A. You asked me a question if I had the details on it and I'm saying I have the details.

Q. The 165,000 pre-tax return on Aberdeen pipeline, can you provide the calculation for that number?

A. Yes.

Q. Can you do that as a late-filed exhibit?

A. Yes.

Q. The $48,000, that's a management fee, isn't it?

A. Yeah, it's a management fee.

Q. Is there any basis for that number time sheet?

A. No, we don't do time sheets. We do profiles of where our costs are allocated. And in the response to data request number 6-12 to the Commission, NEC laid out its cost for providing management services to NPS, laid out its total costs, plus what portion was allocated to the management fee.

The total cost back in 1997 was the total of $1,062,892. 970,200 of that was the NPS management fee

for regulatory services, review of rates, all the regulatory stuff we do for NPS. There was $155,962 of cost that were, you could call it allocated to strategic non-regulated projects.

Q. Did the construction or operation of the Nekota pipeline cause that $588,000 cost to be incurred?

A. Yes.

Q. And how is that?

A. Because, you know, if you would -- if we wouldn't have built the pipeline, Northern wouldn't have needed, you know, dollars, too, you know, but then NPS would have still had the problem of having a contract restriction, wouldn't have had their capacity realigned and they would have still been 10,000 short of firm capacity. They would have had to pay some dollars. They would have had to buy those services from Northern.

Q. Did the $3.20 rate charged by NEC and Nekota cause that 588,000 cost to be incurred?

A. No.

Q. And did the construction or operation cause the need for additional capacity?

A. Did the construction?

Q. Did the construction cause additional need

for additional capacity?

A. No.

Q. Did the construction cause rates to increase?

A. No.

Q. I'm not sure if we've got this date in the record yet. Maybe we do. What was the date that that restriction by NNG was rescinded?

A. I believe that it was -- we probably have the contract here. But I think it was in February of '97 or somewhere in there.

Q. Okay. So negotiations began in May, ended in August of '96. The pipeline is completed, I think you said, by the end of October of '96, and then the restriction is rescinded in February of '97?

A. Right, on NPS's contract.

Q. Is that correct?

A. Yes.

Q. Okay. When was Nekota formed?

A. This is sometime during the fourth quarter of 1996.

Q. After the pipeline was completed?

A. I don't know if it was formed after the pipeline was completed or not. I know that the pipeline was basically in NEC's name and then NEC incorporated Nekota to hold that specific asset.

Nekota was just simply at the time set up to be the company of NEC that would hold physical assets.

Q. Why didn't NEC just keep the asset?

A. Accounting purposes. I mean it's easier to keep assets in one company and for property tax purposes and just cost accounting purposes.

Q. You discussed before about the 5,000 MDQ MMBtu. Do you know what I'm talking about?

A. On Northern?

Q. On NEC's, on Nekota.

A. I'm not exactly sure what you're -- what you're asking.

Q. It's on an exhibit. Did NEC hold 5,000 MDQ MMBtu on the NEC -- or on the Nekota pipeline before Nekota?

A. No. The contract that we have with Nekota, NEC, provides that we buy the 15,000 from Nekota.

Q. Right.

A. And any additional capacity that's required by NEC for former agency customers of NPS.

Q. And that was going to be my question. Are those purchased for marketing customers of NEC or NWPS sales customers?

A. The 1,500?

Q. I thought it was 5,000 on exhibit --

A. Again --

Q. Let me find the exhibit. Okay. Well, let's look at Exhibit 3 and the 6,500.

A. Okay. You wanted to know where the 6,500 comes from.

Q. I want to know what customers did you purchase that for, the marketing customers of NEC or NWPS sales customers?

A. The 6,500 is a capacity that has been assigned NEC for agency business.

Q. Are those marketing customers?

A. Yeah. That's where we recover our cost of that capacity.

MS. CREMER: That's all I have at this time.

MS. WIEST: Commissioners?

CHAIRMAN BURG: Let's start right where we finished. The 6,500 that Northwestern Energy holds, you said that goes to what? That's used for what?

A. That's used for large irdustrial customers like ethanol plants and soybean plants.

CHAIRMAN BURG: Customers of whom?

A. Customers that are directly connected to Northwestern Public Services system. They're inside the -- we're basically acquiring gas supply and capacity on Northern for large end users on NPS's

system.

CHAIRMAN BURG: And you charge them for use for the gas that comes over that pipeline; right?

A. Yes.

CHAIRMAN BURG: Does that offset the 576,000 that the other consumers are paying?

A. No. I'm hoping that it offsets the 248,000 that's assigned to NEC.

CHAIRMAN BURG: NEC is paid 278,000? What was the cost of that pipeline?

A. The Nekota pipeline.

CHAIRMAN BURG: Yeah.

A. $185,000.

CHAIRMAN BURG: So according to this contract, they're receiving 824,000 per year in return, Nekota is, 576 from Northwestern Public Service and 248 from Northwestern Energy?

A. I would characterize it as NEC has 588,000 of costs from Northern Natural and the rest of the cost is basically associated with the pipeline, the 165 and the 23 are direct Nekota pipeline costs, and the 48,000 is just an administrative fee for NEC to nominate, balance, and get supplies off Northern Border for both parties.

CHAIRMAN BURG: I'm getting more confused.

588,000 Nekota pays to Northern Natural?

A. NEC pays that, NEC.

CHAIRMAN BURG: Well, where does Nekota get their money? Okay. NEC pays 588,000 to Northern Natural. Northwestern Public Service pays 576,000 to who?

A. To NEC. Another way of saying it all the project costs, the 824,000, all of those costs are paid for by either Nekota or NEC.

CHAIRMAN BURG: And then who are they charged to?

A. They are charged to Northwestern Public Service, the 576. The remaining $248,000 is left as cost on NEC's books to recover from its customers for pipeline capacity.

CHAIRMAN BURG: Are Northwestern Public Service customers charged 576,000 to offset the one million cost of the pipeline to go to Nekota? How does Nekota pay for the pipeline?

A. How does Nekota pay for the pipeline?

CHAIRMAN BURG: Who do they receive their money from?

A. From NEC. There's a contract from NEC.

CHAIRMAN BURG: Gets it from where?

A. From NPS.

CHAIRMAN BURG: How much?

A. 576,000.

CHAIRMAN BURG: For ten years?

A. For ten years.

CHAIRMAN BURG: And the original cost was one million what?

A. 1,185,000 for the pipeline.

CHAIRMAN BURG: So they're going to collect 5,760,000 in those ten years to pay back the 1,185,000; is that correct?

A. No. I would think that it would be to pay back 824,000 times ten, 8 million dollars of cost of service of this pipeline and project.

CHAIRMAN BURG: So, in other words, they're going to pay eight million for the original cost of one million?

A. No. The pipeline investment is just one element of this whole project.

CHAIRMAN BURG: Okay. That's the next question I was going to have. What else goes into those costs?

A. The firm services that NEC bought from Northern Natural Gas. Northern Natural, I mean these costs could have just simply been put on NPS's books.

CHAIRMAN BURG: And I am trying to figure out

why they weren't because it's whole different customers that gets that benefit.

A. Yeah, the Northwestern Public Service customers.

CHAIRMAN BURG: But not the Aberdeen ones now; correct? Does Aberdeen get any gas from Northern Natural currently?

A. No.

CHAIRMAN BURG: So all of it comes through the Northern Border?

A. Yes.

CHAIRMAN BURG: And so?

A. Only when the line has to be shut down, if it has to be shut down, would we get any capacity from Northern.

CHAIRMAN BURG: That's why I absolutely am not figuring why the costs of the Northern Natural is even included in a Northern Border provisioning pipeline because nothing -- the Aberdeen customers don't get anything from Northern Natural. They get it all from Northern Border and yet you got 580,000 that goes to Northern Natural?

A. Well, I guess another way of looking at this is that you could have put this into two pieces.

CHAIRMAN BURG: It would have sure been a lot

easier for me.

A. This is really two pieces here, the $588,000 is dollars that are paid to Northern and there's capacity with it so it's not like we're just 588 and then it's thrown out the window, 588,000 for NPS to realign its capacity on its contracts, to get additional market firm for no additional cost, by turning back in this firm field capacity and having additional capacity firm to meet its peak day needs.

CHAIRMAN BURG: That's basically for everything except Aberdeen?

A. That's correct.

CHAIRMAN BURG: And that's why I'm having a hard time figuring why it's even attached to the Aberdeen portion because it just, to me, it just --

A. Well, it was part --

CHAIRMAN BURG: -- incomprehensible.

A. But it was part of the -- if that dollar amount would not have been negotiated with Northern --

CHAIRMAN BURG: You couldn't have built the pipeline?

A. The pipeline. I mean there wouldn't have been a pipeline. NPS would have still been short capacity on a firm basis. We had to do something.

CHAIRMAN BURG: Well, that's why I'm having a

hard time figuring how they can keep you captive when they couldn't produce the capacity and yet they can prevent you from buying any place else so you just couldn't absolutely expand or couldn't meet the needs of the customers?

A. Exactly.

CHAIRMAN BURG: You had signed that kind of a contract with them?

A. That contract was signed by someone at NPS back in 1996.

CHAIRMAN BURG: It brings me to wonder why counsel didn't ask why you couldn't challenge that contract when they couldn't. It's as though there's a quid pro quo. You signed the contract saying you'll provide everything we need and we'll take everything we need from you when they could no longer provide your needs.

I don't know how they could hold you to a contract that says you have to take it all from us and you not fight that contract for one thing for the customers of South Dakota. But then when you did get it negotiated, to tie the costs of getting out of that kind of a contract to the new pipeline, which had nothing do with that, I mean I'm having a real hard time tracking how those costs go into the provisioning

here.

A. If there wouldn't have been consideration put to Northern, NPS couldn't have used the pipeline.

CHAIRMAN BURG: Without getting the contract broken?

A. Without getting the contract broken. So you could look at it that this 588,000 is really a buy-out or a buy-down of a provision of a contract that would allow to you do other things.

CHAIRMAN BURG: But I would also look at it it was a method of allowing you to continue serving the customers of those other Parkston -- and I think you named about five of them in there that you could serve once you got this deal done that you couldn't serve otherwise; is that correct?

A. You're going back prior to my time on this but...

CHAIRMAN BURG: Well, you know, again we don't have your testimony because your counsel didn't include it in this hearing, but I read it for the previous case there's about five cities listed that you're now providing service to that you didn't have the capacity to provide them to without this agreement; is that correct?

A. Without this agreement we couldn't have had

Northern build capacity to those communities.

CHAIRMAN BURG: That's right.

A. Actually, I think if you look at the capacity that we're -- that NPS is paying for, it was over and above what those communities are currently using on a peak day. They've got to grow into that. That would be on Exhibit 1.

CHAIRMAN BURG: Do you have an exhibit or do you have anything that shows what the portion of the 576,000 is the payoff of the pipeline and which is for services?

A. I would say it's 588,000 out of the 824 whatever percentage that is, is that's the part of the 576.

CHAIRMAN BURG: What's that again?

A. 80-some percent. I don't have a calculator.

MS. WIEST: Aren't what you asking what portion of the 588 is related to the actual buy-out, or what actual firm services -- what are you getting for the 588, what portion is related to the buy-out of the contract that's -- you referred to that before and what you claim you're buying firm services from NNG? Are those broken down? Is there a contract between NNG and NEC for this 588?

A. Yes, there was.

MS. WIEST: Can we put that into the record?

A. I don't know if we have it here.

MS. WIEST: How long is that contract for?

A. That contract was for an initial five-year period.

CHAIRMAN BURG: But the contract to purchase is for ten years; correct?

A. Yes.

CHAIRMAN BURG: With the renewal for ten more?

A. Yes.

CHAIRMAN BURG: So the potential is to have the customers that receive theirs from Nekota paying for 20 years at a flat right; is that correct?

A. For 20 years?

CHAIRMAN BURG: Right, because you've gotten plus ten at the option of who?

A. I think that's why we did the ten-year deal. I mean, I think the problem was that the contract between NEC and NPS didn't allow for another roll-over. The contract between Nekota and NEC did. I don't think we had any problem with putting a roll-over provision in there and giving that capacity to NPS for another ten years.

MR. DIETRICH: Excuse me, Chairman, we do

have an exhibit that might help here if I could have it marked.

(EXHIBIT NO. 8 WAS MARKED FOR IDENTIFICATION.)

CHAIRMAN BURG: You have some explanation from this exhibit?

A. This is the contract that was finally executed between Northern Natural and Northwestern Public Service that basically resolved all of the contractual and operational issues.

CHAIRMAN BURG: Okay. I haven't had time to read it, but the question I have been trying to get to is what are the consumers that are using the Nekota pipeline, what's it called NBPL, Northern Border Pipeline, you know, what are the consumers that are using those services, what are they paying in return for the building of that, specifically the recovery of the cost of building that, for how long?

Because, in other words, the contract, is it for a flat fee for how many years?

A. Ten.

CHAIRMAN BURG: And what's the renewal? What's the renewal of another ten? Where does that come in?

A. That was -- there was --

CHAIRMAN BURG: That's a choice of Northwestern Public Service; right?

A. That's not in the current contract for another renewal.

CHAIRMAN BURG: You said there's a renewal. Where is that renewal?

A. That's between Nekota and NEC.

CHAIRMAN BURG: NEC, okay. So and whose choice? Both?

A. Yes.

CHAIRMAN BURG: Either or both?

A. Well, it would be NEC. I mean if they want to renew that contract, they can renew it.

CHAIRMAN BURG: Okay. NEC can renew the contract and then conversely continue to charge those customers at that rate; right, at their choice?

A. Well, there would probably be a new value in that contract. I mean the 576 goes for ten years.

CHAIRMAN BURG: Okay. So the renewal is not at 576?

A. Right.

CHAIRMAN BURG: That isn't in the contract?

A. No.

CHAIRMAN BURG: But what I'm trying to get at is how -- you know, how much will the customers -- how

many -- are they going to pay for the construction of that pipeline in whatever period of time your company can choose to use it? That's what I think is important as far as us making sure that they're getting a fair return for their -- what they're paying.

Because with all the intertwined companies, it doesn't make any difference who charges what as long as they get the money. The rate payer -- the shareholders are going to get the money whether it's Nekota, whether it's NEC, whether it's the NWPS, whether it's NPS, as long as it stays within that family, the shareholders are going get benefit.

I'm trying to figure out are the rate payers getting screwed to give the shareholders that benefit? And I don't see the adequate trail, okay, to do that, to know what they're paying for that new pipeline you built because you're paying 588,000 to buy out another company.

And from what you've told me, you're charging part of that to these customers to get the ability to buy this. Then you're turning around and charging them at a rate that I can't determine to pay for the construction of that and the rate payers. And it was never brought before this Commission for approval of that transaction.

So what are the rate payers getting charged in order for you to generate this kind of income for the shareholders?

A. Well, the income for the shareholders is based on the project cost of $165,000 a year pre-tax on that $1,185,000 investment. And of the 576,000 dollars, a small portion of that 165 -- take a few minutes here. And all I did was took the pre-tax return on the Aberdeen pipeline and the property taxes on the Aberdeen pipeline, and took those costs divided by the 824 for just the Aberdeen pipeline piece itself, just for the return on the property taxes on that line, just that cost element was 131,000 of the 576.

CHAIRMAN BURG: Okay. That doesn't tell me. I'll have to have somebody go through the calculation to see, you know, what percentage return you're getting on that one million investment is what I'm really looking at.

A. Okay.

CHAIRMAN BURG: Just on the one million investment?

A. That's on exhibit -- that's in my rebuttal testimony.

CHAIRMAN BURG: But I can't use that.

MR. MOLSTAD: You can't use it. You have to

testify to what it is.

A. It's taking the revenues of the project, including the 576 from NPS and backing out the cost that NEC and Nekota incurred pipeline charges on Northern, property taxes, you take out those direct costs from the revenue stream, you have a pre-tax operating income of $165,844.

CHAIRMAN BURG: What comes out as a percentage?

A. That came out as a percentage using the capital structure and embedded debt and preferred stock cost approved in Northwestern's last rate docket NG94-008, of 12.3 percent return on common equity.

CHAIRMAN BURG: In other words, we're saying that there's only 62 percent of the capacity that is really being used to deliver gas to Aberdeen; is that correct?

A. The 62,000 is -- the 15,000 is all that we're assessing a charge to NPS on.

CHAIRMAN BURG: Right.

A. They have the ability to use by contract the full value of the line.

CHAIRMAN BURG: I understand. But what they're not using, now does it sit vacant?

A. Yes, it sits vacant.

CHAIRMAN BURG: You said NEC holds that amount; right?

A. Right.

CHAIRMAN BURG: To use for firm customers?

A. Right. And that's part of the revenue contribution to this project is the value of that capacity.

CHAIRMAN BURG: And does that offset --

A. The cost?

CHAIRMAN BURG: Does that offset the cost of --

A. That offsets the cost of the project. And that during the test period was $57,532.

CHAIRMAN BURG: Okay. You're saying that Northern -- Northwestern Energy is liable for 248,000 also; correct?

A. Right.

CHAIRMAN BURG: So you just told me that the shareholders get approximately 12 percent from the Northwestern Public Service customers for the use of that line; right?

A. The return on that line, yes. That's the return 12.34.

CHAIRMAN BURG: Don't the shareholders also get the 248,00, the profit on that?

A. No, that's expense. That has to be sold to somebody to recover that cost.

CHAIRMAN BURG: And when you recover that cost, where does that income go?

A. That goes revenue.

CHAIRMAN BURG: Right, right, that's what I mean.

A. If your cost is 248,000, and hopefully we can sell it for 248,000, then we're even on that transaction, and then you just add gas costs on top of it.

CHAIRMAN BURG: I'm lost but I'll let it go. Okay. That's all I have.

MS. WIEST: Getting back to this contract that we just were handed, are you saying that pursuant to the terms of this contract, NEC is paying Northern Natural Gas $588,000 for five years?

A. Yes.

MS. WIEST: And can you break this down and show me what portion -- what expense is attached to each part of this? You must have gone through this. I don't see 588,000 listed and actually have not read the whole thing yet. But I assume there's a value for each of these services in here. But is there -- do you have anything to back that up?

A. I'm trying to -- what exhibit are you looking at?

MS. WIEST: It hasn't even been marked. It's your contract between NEC --

A. I've got a contract here between Northern and Northwestern Public Service dated February 6, 1997, that's Exhibit 8.

MS. WIEST: Okay. Then this is not the contract between Northern National Gas and NEC?

A. No.

MS. WIEST: Do we have that?

A. I don't have it.

MS. WIEST: Is there a contract that exists between Northern Natural Gas and NEC that states that NEC is paying Northern Natural Gas $588,000 a year for five years?

A. It doesn't state that it pays 588. It states that it buys 5,000 per day of firm pipeline capacity at a base rate, plus surcharges. And then on the deferred delivery service it's stated at whatever Northern's maximum rate is. And so during the course of a year, whatever those surcharges and charges and use of that is, that produces the cost.

MS. WIEST: And that is always $588,000 each year?

A. No. It could be higher or lower than that. You know, Northern just passed a new increase or change in rates, and the cost of the firm delivery service is going to go up.

MS. WIEST: And so what is the 588 based on?

A. Whatever the contractual rates and terms of that contract are. And if it's at a full rate service it's at Northern's tariff rates.

COMMISSIONER NELSON: We don't know what that rate is today; right?

A. Today.

COMMISSIONER NELSON: Well, we might know today. We don't know what it is tomorrow. It might be more; it might be less. Is that right?

A. The rate should stay the same until Northern files a tariff change.

COMMISSIONER NELSON: Even if they file the tariff change, you picked the number 588. How do I know that's the actual amount that you're going to be paying them, 588? You said you only contracted to buy so many 5,000 whatever it was. And but you don't know what that 5,000 is going to cost. Is that right?

A. Well, yeah. The cost is going to be -- there was a stated base rate in the cost in the contract. The summer months were $3.00 and the winter months were

3.50. Plus any of Northern's surcharges per their tariff plus fuel, plus surcharges that was for the firm transportation. The firm delivery service, the firm delivery service was 300,000 capacity at whatever Northern's tariff rates were at the time, and those are different today than they were you know three years ago. Northern had a rate change. And the 588,000 is the actual costs that were incurred during the 1998.

MS. WIEST: What I'd like to do is put this Exhibit 8 into evidence, if there's no objection, and I would like to get the contract between Northern Natural Gas and NEC. Is that possible?

MR. DIETRICH: Yes, we will provide that. We would -- as we've marked this Exhibit 8 confidential, we would like to have this treated as confidentially as possible because it does, contrary to the earlier contract, this does contain provisions that are currently in effect between Northwestern and Northern Natural. And as we deal with a competitive natural gas industry, we would like to safeguard that information as much as possible.

MS. WIEST: Now, this contract Exhibit 8 is only for five years; is that correct, or is this a ten-year contract?

A. I believe that this contract is just kind of

an extension of the current contract that NPS had which terminated November 2nd, 2003.

MS. WIEST: So where is the ten-year contract? I thought there was a ten-year contract.

A. That's between NEC and NPS.

MS. WIEST: Do we have that one yet?

A. Between?

MS. WIEST: Can we have that contract also? Is that a problem?

MR. DIETRICH: No.

MR. MOLSTAD: No.

MS. WIEST: Can we get that one too?

MS. CREMER: That's between who?

A. NEC and Northern.

MS. WIEST: And NPS.

A. You have the contract between NEC and NPS. That was part of the data response to --

MR. MOLSTAD: Not in this proceeding.

MR. DIETRICH: We will provide it.

MS. WIEST: That contract is for ten years?

A. Yes.

MS. WIEST: But this contract is for five years, the NPS and Northern Natural Gas, Exhibit 8?

A. I'm not exactly sure you could say it's for ten years because Northwestern is agreeing to extend at

least 30,000 in provision two. They're giving Northern a commitment of at least 30,000 MMBtu per day on a service off of Northern that would run through October 31st, 2008. Northern was extremely nervous about NEC building pipes from Northern Border to Brookings, to Mitchell, to Huron, just like we did at Aberdeen. And the economics are not quite there on some of those but certainly it's something that we will look at as these contracts expire in 2003.

And that's just like this Nekota pipeline. We're going to try to do everything we can if we have to negotiate with Northern again for a lower rate. If they don't give it to us, we're building it.

MS. WIEST: So what did the 588,000 give Northern Natural that they wouldn't have gotten otherwise? I mean are you paying for firm service you don't need?

A. No. NEC could certainly use that capacity. This was dollars they said -- okay. They said in order for NPS to get out of the contractual terms that is present in certain of their contracts and for realignment and for NPS to use this pipeline up at Aberdeen, even if NPS would have owned the pipeline themselves, they wouldn't have been able to use it because they would have been buying from Northern

Border rather than Northern Natural. Okay?

And so there was going to be some dollar buy-out. Well, at least we're getting some capacity with that dollar buy-out. And NEC is trying to mitigate through selling to larger customers, get ethanol plants on our system to mitigate that cost.

And, you know, it's part of this project. This was -- I wish it was as simple as we could have built a pipeline and Northern didn't have any thing over our heads that we could have used it, the cost of service to NPS would have not been 576,000. It would have been less.

MS. WIEST: Is part of the 588,000 for firm service but another part for, in realty, the buy-out of the contract?

A. You could talk about it that Northern wanted an economic dollar amount and they were going to give some capacity that was attached to that.

MS. WIEST: And can it be divided out between the two, this is how much it cost to buy out the contract?

A. I don't think so.

MS. WIEST: At the end what period will the terms leading to the 588,000 be no longer subject to contract?

A. Between NEC and NPS?

MS. WIEST: Yes.

A. I thought that was a ten-year deal. Which contract are you referring to? The Northern and NEC contract. Northern and NEC that runs for five years and --

MS. WIEST: What will happen at the end of that?

A. What will happen at the end of that?

MS. WIEST: It just expires?

A. Yes.

MS. WIEST: Then why are you continuing to charge NPS the 576,000 for another five years?

A. Well, NEC has to get capacity for itself on Northern's system. And, you know, when that contract expires, we'll have to renegotiate another contract with Northern.

MS. WIEST: But you have no idea what that renegotiation will be, but you're just assuming?

A. I would assume it won't be at a lower cost than what they provided us in the first contract. They've got some riders in this current contract that if they can get a higher value for it from someone else, we either have to match that higher price or lose the capacity.

MS. WIEST: Since we've been referring to it as a buy-out of the contract, is NPS now free to build any pipelines it wants to to Northern Border?

A. NPS is free to use other parties rather than Northern Natural.

MS. WIEST: Today?

A. Yes. That is in Exhibit 8, the last page three, number eight, Northern agrees to waive paragraph four of their November 20, 1999, letter. The parties further acknowledge that there are no agreements known or unknown in effect that would restrict Northwestern's ability to serve any markets through transportation services provided by parties other than Northern.

I did not want them to bring out another piece of paper at any point in the future that restricted us in any way. If they had anything that they were known at that time, show us now. During negotiations they just wanted to still limit that to Aberdeen. I said, no, we don't want to limit it to Aberdeen. We want to be free to go elsewhere if it's in the best interests of the customers.

MS. WIEST: Why did Northern Natural resist realigning delivery point capacity? I think you have that as one of the project benefits.

A. Because it's a creative way for them to hold

LDC's hostage to buy more capacity from them.

MS. WIEST: Could you compare and explain field firm versus market firm?

A. Field firm is capacity that's south of a point in Kansas which is demarcation. Northern calls it a demarcation point. It's simply an imaginary point on their system that prior to that point gas flowing from the south to that point is considered firm field transportation because it's connecting producing areas, and once it hits demarcation, it enters Northern's market areas where there is no production areas.

MS. WIEST: Who's paying the operating and maintenance expenses on the pipeline?

A. On Nekota pipeline?

MS. WIEST: Yes.

A. Any operations and maintenance that would be incurred on there are paid by NPS during the first five years of the contract.

MS. WIEST: And how are those costs reflected?

A. They would be reflected on the books and records of NPS's operations expense.

MS. WIEST: I don't know if I have this right but did you say NEC contracted originally with NPS to design and construct --

A. Yes.

MS. WIEST: -- the pipeline?

A. Yes.

MS. WIEST: NPS designed and constructed the pipeline. Then did NEC pay NPS for that design and construction?

A. Yes. That was part of the consideration of the 1,185,000 investment.

MS. WIEST: You've got into the evidence the 1996 proceeding. I believe that was Exhibit No. 5, NG96?

A. Yes.

MS. WIEST: That proceeding wasn't filed to consider the Northern Border Pipeline project, was it?

A. No. The Northern Border Pipeline project hadn't even been started at this point. This was filed, I believe, July 1 of '96, subject to check.

MS. WIEST: Do you think there was any specific approval of that project in this filing?

A. Yes.

MS. WIEST: Would NPS then support filing a more comprehensive report of each line item in its monthly PGA?

A. Yes.

MS. WIEST: Does NPS always use the 70

percent, which I think on your Exhibit 3 you compared to 15 MMBtu's?

A. Uh-huh.

MS. WIEST: Did you say yes?

A. Yes.

MS. WIEST: That's all I had. Does the Commission have anything else?

CHAIRMAN BURG: I'm confused enough.

COMMISSIONER NELSON: I have one question though and it goes back to the refund that Ms. Cremer asked for. You said that -- and you had your exhibits that showed that there was a Commission order and a tariff that was approved by the Commission and it somehow blessed this construction, this pipeline?

A. I don't know that it blessed the construction of the pipeline. It included the cost, the purchased gas cost as a result of the negotiations with Northern and building this pipeline.

COMMISSIONER NELSON: Is it not true that -- are you trying to convince me now that we would just automatically have picked that up out of that the document that you submitted in the tariff?

I mean I found the whole subsidiaries and the different companies somewhat confusing, Northern Border, Northern Pipeline. Are you trying to convince

me though -- would you like me to believe that we should have picked it up and that we did pick it up that you bought and constructed the pipeline? I mean you introduced -- why is it relevant for me to consider?

A. I mean until this pipeline was brought in as an issue in the rate case, I was -- I didn't even think that there was a problem. I mean I had to really go back into old books and records just to dig up these transactions on this whole project to start with. I mean this is over three years ago. And I can't remember specifically each and every item that Dave Jacobson would have asked me on that particular PGA sheet. I know we worked together on it. I certainly wasn't trying to hide anything. I mean this was a cost that was out there.

COMMISSIONER NELSON: It's a cost that was out there, but is there some kind of an approval process where if you construct the pipe -- I mean I'm kind of curious why Mr. Bettmann wasn't aware that you constructed the pipeline.

A. Well --

COMMISSIONER NELSON: Certainly it's significant. In your mind it was significant investment. So I'm kind of trying to figure out -- and

since there is a pipeline safety program in South Dakota, when was it going to pop up on our list of things to look at?

A. That would have been an operational issue in my mind, not -- I mean if there's people -- anybody to blame here, I mean -- I think I came up with a creative solution here for NPS management to get some capacity for its customers at a lower alternative cost than just going to Northern and taking the capacity there at maximum rates because that's the history of what Northern charged for capacity.

COMMISSIONER NELSON: Now, maybe I lead to the wrong conclusion. I gathered you were referring to that cost through the PGA.

A. Yes.

COMMISSIONER NELSON: Which in my mind seems to reflect the actual costs of buying commodity and providing to people since it's outside the rate base. I might be wrong, and if I am correct me because -- I mean is that correct or not?

A. I don't know.

COMMISSIONER NELSON: Maybe I reached the wrong conclusion.

A. I don't know if I really followed your question there.

COMMISSIONER NELSON: Well, I'm just trying to figure out if you have a pipeline and you're using it, it gave you more capacity, and you don't tell us that you built it necessarily. But if we want to play -- look at every report, we might be able to figure out. I think without somebody bringing it to our attention, we might be able to figure it out you built the pipeline. But unless at some point in time you come in for a rate case, how am I to know how you expect us to address that cost and the recovery of your cost?

Now, it appears to me that you addressed that probably creatively yourself and you put it in the PGA. Otherwise, how would I know that you were going to -- how you intended to, A, that you built the pipeline, or how you're going to address recovery of those costs and how that's going to affect the rate?

A. If I can say I'm sorry, I'm sorry. And I guess in the future I don't know if this Commission wants every specific strategic projects that NEC or Nekota or NPS is looking at. But if that's what's required, you know, we'll be more than happy to sit down and discuss these strategies. And the problem is if you discuss it with one set of staff, three years later it could be brought up in a base case and the

same players aren't around.

COMMISSIONER NELSON: Well, I don't know if I can buy into that because our staff has been -- I mean 18 years, 15, been around a while, but that's not relevant.

And for me this is really one of the first rate cases that I've been involved in. And I've been operating with one set of guidelines that I thought applied to rate cases, and now I'm not sure that they do because I didn't recommend other things that were being constructed or paid for because I was always told that they -- well, it's not relevant because they're not passing those costs on to the consumers. And if they were, they would be in here for a rate case.

So I was always fairly comfortable with the idea as long as they don't affect the rates people paid at some point in time, you would decide when you wanted to recover those costs and pass them on to consumers. But now I find there's a loop hole somehow for me in that you've managed to find a way to pass those costs on to the rate payers and I wasn't even aware that -- I think for me, anyway, $588,000 is a lot of money, and it certainly has a significant impact on rates.

So I guess I'm trying to figure out how in my mind I'm supposed to address in the future and now your

recovery of those costs and how that impacted the rate payer. Because I always assumed it was going to be through the rated case and they weren't being passed on.

A. They wouldn't have been passed on through the rate case because the investment was not an NPS investment. It was a non-regulated investment.

COMMISSIONER NELSON: But you're passing some of those costs, isn't it? Maybe I'm wrong. I might be mistaken here too. But it seems to me you're trying to pass some of those costs on to the regulated rate payers, although you said that they were non-regulated costs, or the company that authorized those costs were non-regulated?

A. Right.

COMMISSIONER NELSON: But now you're trying to recover those costs from regulated rate payers?

A. For the services that were provided, yes, and it's a supply-related cost. Capacity is a supply-related cost. It's not an investment in a distribution system in meters and lines and regulators. It's a cost that's incurred prior to the town border station prior to NPS's system.

COMMISSIONER NELSON: Is there anything that precluded you from selling? I mean since you have

capacity, I mean I'm not sure how much capacity is adequate. And at one point you decide that enough is enough, I mean. So if we're not using that capacity, all the time there's capacity there that you could be letting other people use, does that happen?

A. Oh, yes.

COMMISSIONER NELSON: And it happens regularly. So how am I to track how much you're making when you're not using it? I mean, in other words, you built capacity for your biggest, worst scenario, the peak time, and I don't know for myself and I don't think that you probably know either how often you're going to have use that, arrive at that peak time because you don't really know if that we're going to have another winter like we did and those costs are going to be up. If we have a good year we won't reach that peak time.

So it seems to me you could be earning a lot of money over the time by using the capacity you really have reserved for yourself. And I'm assuming if you needed it, you would be using it and you wouldn't be selling to somebody else. So you have got your need met and you could make money on that all along; is that not correct?

A. No, no, any capacity that NPS holds that is

sold on the market, those dollars get credited back to the PGA. The gas customers get that benefit 100 percent.

COMMISSIONER NELSON: So any excess money you're making on your things --

A. Yes.

COMMISSIONER NELSON: Got it. Thanks.

CHAIRMAN BURG: Just probably going back to square one, curiosity, as long as you determined it was a proper procedure to recover the construction of that pipeline through the PGA, how did it get into the rate case?

A. There was a schedule that -- two things: There was of a schedule that's attached. I think it's statement R to the rate case. And it talks about listing any affiliated transactions that the utility has with its affiliates, dollars, and that amount was listed there.

And then there was a series of data requests that wanted some more information on those affiliate transactions. Most of them were the management fees and so forth. This just happened to be an affiliate transaction as a gas cost.

CHAIRMAN BURG: But you're asking to recover it correctly in the rate case?

A. No, no, it was already -- all they ask is list any contracts or fees for services between an affiliate and the NPS. This 48,000 a month, or 576,000 was identified as monies that go to NEC, a cost to NPS, and it was a gas cost.

CHAIRMAN BURG: You thought that was part of the reason for the reduction from the two point something million down to the one million?

A. Yes. Bob Towers took the 576 and said it should be 106.

CHAIRMAN BURG: That's what I was going to say. So you had been recovering it through the PGA but now you have also included if through recovery?

A. No, no.

CHAIRMAN BURG: Then how can he take it off because it wasn't there?

A. Because he took it out and realized it wasn't in the base rate and it wasn't in there to start with. His testimony clearly discusses that, that it's now -- he shouldn't have taken out of the base rates because it really is a PGA issue.

CHAIRMAN BURG: Okay.

A. That's why we went from 402,000 to 878.

MS. WIEST: Any redirect?

MR. DIETRICH: Yeah, I have a couple

questions I'd like to ask.

MS. CREMER: I don't believe this is a tag team effort.

MR. DIETRICH: We don't need to. I thought it would go smoother

REDIRECT EXAMINATION

BY MR. MOLSTAD:

Q. Mr. Hitchcock, the costs that are incurred in this project, Nekota pipeline that we've talked about, are those assigned to just Aberdeen itself, or are those assigned to the other particular towns as a whole?

A. They're not directly assigned to Aberdeen as NPS has basically a pool of gas supply costs that it uses. We don't have a different gas supply component for Aberdeen versus Mitchell versus Huron. It's a system-wide cost.

Q. I believe that the question was asked of you, you know, what the total amount was paid for the pipeline. I believe you testified that was the $824,000 was the project cost; is that correct?

A. The project cost of service in 1998 was 824. The pipeline investment I was talking about was 1,185,000.

Q. Isn't it correct that the costs that would

have been paid by NPS to Northern National without the pipeline project would have been much greater than paid under this arrangement? Is that correct?

A. Yes.

Q. And, again, roughly what would have been the additional costs paid by the consumers under the old system without the pipeline construction?

A. That amount would have been for an additional 15,000 MMBtu per day on Northern at their average price that would can be close to 1.2 million dollars a year.

Q. So the savings to the rate payer was?

A. Roughly half of that.

Q. I just want to clarify here a little bit the process on the purchased gas adjustment. This purchased gas adjustment provision, that's separate and apart, isn't it, from the rate base recovery mechanism itself?

A. Yes. Our current tariff has a base rate which is really the cost of delivery service and the customer charge separate from the purchased gas adjustment tariff. They're separate charges.

Q. And that charge for the purchased gas adjustment is provided through a mechanism by South Dakota statute; isn't that correct?

A. Yes.

Q. So there's a separate mechanism for recovery of base rate costs and a separate mechanism for recovery of your purchased gas adjustment costs?

A. That's correct.

Q. So in recovering these costs of this $576,000, isn't it true that you just used the mechanism provided by statute; isn't that correct?

A. That's correct.

Q. I want to go back just a second to the Exhibit 5, I believe, which the Aberdeen pipeline through Northern Border was alluded to. Do you remember that exhibit?

A. Yes.

Q. And I believe that was on Exhibit C; is that correct, as has been identified by yourself?

A. Yes.

Q. Now, just so you understand the process here, this was part of a data request through this proceeding that you provided this information; is that correct?

A. That's correct.

Q. And when you provided that information, I would presume it's well scrutinized by the staff at the Public Utilities Commission?

MS. CREMER: I would object to that.

A. I can't answer that. I don't know that

answer.

Q. I'll withdraw that question. It is provided to the staff; correct?

A. It's provided to the staff, yes.

Q. They have the opportunity to review the terms and to ask any questions that they might have; isn't that true?

A. Yes.

Q. If I understood your testimony that you weren't trying to hide or cover up any transaction in this mechanism; isn't that true?

A. No.

Q. In fact, isn't it true that through the building of the Nekota pipeline you actually saved the rate payers over $500,000 from what they would have had to pay over Northern Natural?

A. I feel because of the efforts of the NEC group that went and negotiated with Northern and got the wheels going on this, that this was truly a benefit to the South Dakota rate payers.

Now, it may not have been -- I can see a lot of confusion here today. There's no doubt that the pipeline costs $1,185,000. I'm not denying it. But there is a cost to providing this service. And, in my opinion, based upon the books and records, it's

$824,000 a year, and NEC shares part of that responsibility and NPS shares part of that responsibility. And that responsibility is shared in basically in the percentage that each gets capacity.

And had we done it again, I don't know what forum we would have done it in, to come to staff and say we are working with Northern and would you approve this. I don't know what kind of a proceeding we would have had. We did the best we could. I'm torn that, you know, there's this issue.

Q. And again alluding to Exhibit C of Schedule C of Exhibit 8, (sic) I believe you indicated that the way that the NBPL - Aberdeen capacity is listed there is no different than you list any other item on that particular exhibit; is that correct?

A. That's correct.

Q. So you weren't trying in any way to cover that up or hide that at all; is that correct?

A. That's right.

Q. And I believe then also this same method of the purchased gas adjustment that's been used on a monthly basis for approximately the last three years?

A. Yes.

Q. And, again, that every month the information is provided to the staff; is that correct?

A. It's provided in a filing to the Commission.

Q. And, again, that's through the purchased gas adjustment provisions by statute?

A. Yes.

MR. MOLSTAD: I have no further questions.

MS. WIEST: Any further questions?

RECROSS-EXAMINATION

BY MS. CREMER:

Q. Your attorney asked you a question on redirect and you referred to the $197,000 benefit. That benefit would only have -- that amount is assuming that litigation would have been unsuccessful; isn't that right?

A. No. That's assuming if we wouldn't have even had to talk to Northern, we would have required 15,000 MMBtu of capacity and went to Northern and say we want this much capacity and that's what the value of that capacity would have been worth in a contract.

MR. MOLSTAD: I have a question then.

FURTHER REDIRECT EXAMINATION

BY MR. MOLSTAD:

Q. So isn't it true, Mr. Hitchcock, that you would have been, under the Northern Natural scenario, it's over a ten-year period, we would have been eluding the ten yearly periods that you would have saved the

rate payers ten years, times roughly $500,000, or roughly $5,000,000 plus over that time period; is that correct?

A. Yes.

Q. So even though the costs may have been eight million, you actually saved the rate payers over five million during that time period; is that true?

A. That's correct. And then you haven't added in the benefits of the capacity release credits that are there and just the fact that there's no fuel and variable charges on the Northern Border pipeline. There's tremendous value that is returned. The $576,000, NPS is getting substantial credits against that.

Q. Which then would reduce the cost to the consumers; is that correct?

A. Yes.

MR. MOLSTAD: That's all I have.

MS. WIEST: Any further questions of this witness? Thank you.

Do you have any other witnesses?

MR. MOLSTAD: Yes, one -- or two, excuse me.

MS. WIEST: We'll take a break then. Ten minutes.

(EXHIBIT NO. 9 WAS MARKED FOR

IDENTIFICATION.)

MS. WIEST: Let's get started. Call your next witness.

MR. DIETRICH: Rodney Leyendecker.

RODNEY LEYENDECKER,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. DIETRICH:

Q. Please state your name for the record.

A. Rod Leyendecker.

Q. And what is your current occupation?

A. I'm president and CEO for Northwestern Energy Corporation and president and CEO of Norcom Advanced Technology, incorporated.

Q. Okay. And were you employed by Northwestern in 1996 and 1997?

A. Yes, I was.

Q. And what was your position at that time in the winter of '96/'97?

A. I was vice-president of market development, which was the group that transcended into an unregulated business of Northwestern Energy and then spun down into the telecommunications.

Q. So you were involved in the transactions and

the discussions leading up to the Nekota pipeline construction?

A. That's correct.

Q. Okay. There's been some suggestion that the company was less than forthright in its presentation of information to the Commission staff or Commission with regard to this pipeline. Do you agree with that?

A. I don't know if I can say that we jumped on the table and said, "Here we are." It was a non-regulated activity, the construction of the pipeline.

I am very disappointed to hear the thing portrayed as we hid it, because frankly I'm very proud of what we did. I always stated that we offered Northwestern -- we, Northwestern Energy Corporation, through Nekota Resources, offered Northwestern and its customers capacity at 40 percent of what it was available from Northern Natural Gas Company.

Now today I heard Tom testify 60/55 rate. That represents a blended rate over the season. So he took every precaution to lower it and not overstate the benefit to the customer. I used to refer to it as 40 percent of the alternate rate. So I'm very disappointed that it's been -- and very proud to be able to offer that.

What I hear today -- and, frankly, the stuff was a little old in my mind, but during the morning session here I got pretty well refreshed on it. What I heard is Northwestern Public Service Company pays $576,000 for capacity from that as a result of it there is roughly, I heard, even in the lower year, $200,000 credit against that for released capacity. And I believe there was another $100,000 in fuel and other Northern related costs that would have been associated had they been the supplier as opposed to NEC.

That kind of comes down to about 276,000 versus that million, 20 cents on a dollar. And somehow we're supposed to be ashamed of that? I don't think we should be.

I heard a lot today about recovery cost. I think there's been a lot of confusion. There's PGA recovery, there's base rate recovery, hey, there's another world out there is why it's recovery of unregulated cost and that's not a regulated activity. So the fact that the pipeline costs 1.85 million dollars, if Northern Natural's value of their capacity is nine dollars, I'll tell you what the value of the pipeline is, it's nine million dollars. It doesn't -- it just means it was a good decision on the part of Northwestern Energy Corporation to do that.

We had other pipelines on the board to do. It was mentioned this morning Watertown was one of them we would like to have done, that we just weren't able to work out the logistics to get it done. They did it themselves.

The evaluation of the name Nekota is the -- Nekota is a derivation of Nebraska and Dakota, the supply area of Northwestern Public Service Company, our affiliated utility. We intended to put a number of pipelines wherever. This was an opportunity to do something better for the customer and for Northwestern Energy. We wanted to do it. Right now I don't know that that -- that we shouldn't agree to re-think that some. In any event, I ran on a little bit.

Q. During the spring of 1997, were you part of a meeting between Northwestern Executives and representatives of the Public Utilities Commission and their staff at which a number of pieces of information were shared with the Commission?

A. I can remember that I made a couple of presentations to the Commission where we invited the Commission and staff over, and one of them in particular was when I was market -- in market development and we shared some of those things.

Q. Looking at what's been marked Exhibit 9, are

those excerpts from the presentation that was made at a meeting that spring?

A. I see it's consecutively page numbered, so it would be excerpts of the entire presentation, but it represents the entirety of my presentation.

Q. Okay. Do you recall any specifics from that presentation?

A. You know, I'm getting aged here somewhat and I don't recall. But I mean as I go through the thing, it's pretty clear what the message would be here is that I was talking about mechanisms and strategies that would protect customers for Northwestern Public Service Company.

I come in here -- you know, some of our activities that we were doing on a contracted basis for Northwestern once we became incorporated was tariff maintenance that would protect margins, enhance customer choices. Ultimately as we got down into the NEC operation, that's exactly what we've done.

I see on the second slide that we talked about some of the strategies of gas pipelines. That's what we did do.

The next page is more general. The page after that somewhat, I guess, was to depict a contracting, if you will, service-regulated business

for what we thought where it was going, that it was going to become a pipes and wire business. That means that upstream of TBS and perhaps the same thing on electric side, once it advances along, we'll become unregulated, deregulated. That was the whole message on that particular series of slides.

On the next one, Foundation of American Development there we have got Northwestern Public Service Company, which structurally was the parent company in 1997. Northwestern Corp. has been a reorganization much patterned after -- I don't know if it was patterned after, but much similar to the way Black Hills is right now whereby Black Hills Power is just a division within Black Hills Corp. Then I assume they have a number of subsidiaries, some of which I'm familiar with.

But as you see there, Northwestern Public Service Company, subsidiary Northwestern Energy Company and a subsidiary Nekota. Now, I don't know what I said in particular that day, but the fact that I got Nekota on here and Nekota has one single purpose in this whole world and that is to own and operate the one pipeline that we own. I don't know what I could have said other than that that day. And I guess, you know, that would be my response.

Q. Okay.

A. And I certainly would indicate that at least that particular day I wasn't intending to hide anything.

MR. DIETRICH: No further questions.

MS. WIEST: Ms. Cremer.

CROSS-EXAMINATION

BY MS. CREMER:

Q. Thank you. Who was present at the meeting that you were just discussing?

A. A number of Northwestern Public Service Company people. The presenters are on listed on top of exhibit so I assume they're there.

Q. Right.

A. I guess maybe you could go around the table and probably get a better hands than I -- I know some of the Commissioners, if not all, were there, some staff, if not all, were there.

Q. And if I understood you right, you really don't remember what you said that day?

A. That's correct, but I think I drew some pretty concise conclusions of what could have been said.

Q. What could have been said at the meeting, but we don't know what was said, do we?

A. Yes. But when there are single issues like Nekota Resources, you can say nothing else unless you're just plain making it up.

Q. It says Nekota Energy, it doesn't say anything in here about Nekota pipeline; is that correct?

A. Nekota Resources has one single purpose in life.

Q. I don't see Nekota Resources.

A. Maybe it got misnamed in there. It got misnamed. But there is no such thing as Nekota Energy. I'm sorry, it is Nekota Resources, Nekota Resources single purpose.

Q. And so you believe at that meeting you told the Commission that we're building a pipeline and it's running into Aberdeen and we've got the rate in the PGA?

A. No. The indication on here, Counselor, is that it was April of '97, so it would have been built and operating.

Q. Right.

A. I would have talked about how we -- I probably said we built a pipeline and saved supply capacity at 40 percent of tariff rates. That would be the guess on my part.

Q. Was it, "we built the pipeline and it's the one running into Aberdeen right now and it's the one you guys all know about"? You wanted to use that as an example?

A. That would be your words. What I said was a likely comment I would make about that is that Nekota is the owner of pipeline in Aberdeen with which we supply capacity to Northwestern Public Service Company at 40 percent of Northern's tariff rates.

That would be the only kind of message I could have derived. And I'll state it the way Tom calculated today at 60/55 for a blended seasonal. I would have been overstating the discount but -- or understating the price, but that's the way I always refer to it.

MS. CREMER: I have nothing further.

MS. WIEST: Commissioners?

CHAIRMAN BURG: Probably the only one I'd have is a lot has been cleared up for me from the time I first started asking my questions until later. But how did you not recognize that construction needed inspected? That's the one issue.

A. The construction needed inspection?

CHAIRMAN BURG: Right.

A. To be honest with you, I have no knowledge of

the requirements. Only in the break I visited here with Curt Pohl, who I would say should be more familiar. He's not aware that we have ever filed under anything to be constructed. And perhaps you're going to put him on the stand. I don't know.

CHAIRMAN BURG: I'm trying to recall, when did we take over pipeline safety inspection? I can't remember that.

A. Based on at least the short the break we got, Commissioner, I don't think we've ever filed based on what Curt can remember.

CHAIRMAN BURG: But even if it -- even if we weren't required -- we didn't have pipeline safety yet, the Feds should have been aware of construction and supervision as it's being constructed.

A. Yeah.

CHAIRMAN BURG: Since this is your first pipeline, I mean.

A. Actually, we've been involved in construction with Northern, I think, on a couple of pipelines. But all I'm saying is Curt says he's unaware of it and apparently that means we never have.

CHAIRMAN BURG: Okay.

MS. WIEST: Any redirect?

MR. DIETRICH: No.

MS. WIEST: Thank you. Any further witnesses?

MR. DIETRICH: No, we do not.

MS. WIEST: Ms. Cremer.

MS. CREMER: Thank you. I would call Dave Jacobson.

MR. DIETRICH: Excuse me, could I offer Exhibit 9 at this time?

MS. WIEST: Is there any objection?

MS. CREMER: Do I understand correctly this wasn't the whole -- this was just Mr. Leyendecker's part? That's all that's in there?

MR. DIETRICH: This was just Mr. Leyendecker's presentation. There were presentations by all of those executives that were shown there. We certainly could provide the rest of that presentation. We just felt that it was not pertinent to this issue.

MS. CREMER: No objection.

MS. WIEST: Exhibit 9 has been admitted. Just for the record, was there any objection to Exhibit 8, the February 1997 contract? If not, we'll admit Exhibit 8.

DAVID JACOBSON,

called as a witness, being first duly sworn,

was examined and testified as follows:

DIRECT EXAMINATION

BY MS. CREMER:

Q. Would you state your name and address for the record, please?

A. Yes. David Alan Jacobson. My address is Public Utilities Commission, 500 East Capitol Avenue, Pierre, South Dakota.

Q. Where are you currently employed, Dave?

A. I'm an analyst at the Public Utilities Commission in Pierre.

Q. And could you give us your educational and employment background beginning with high school graduation?

A. I graduated from Huron High School, 1976, graduated from the University of South Dakota with a BS in business administration in 1980, and subsequently went back to school and completed major course work in accounting. I'm employed by the Commission in 1984 as a utility analyst and continue to be employed by them today.

Q. And you have testified before the Commission on numerous dockets on numerous occasions?

A. Yes.

Q. Are you familiar with Docket NG99-002?

A. Yes.

Q. And did you hear Mr. Hitchcock's testimony earlier today concerning the PGA issue?

A. Yes, I did.

Q. From staff's perspective, what's the issue here and what is your recommendation?

A. The issue involves payments made by Northwestern Public Service to its affiliate Northwestern Energy Company for the purchase of pipeline capacity from Northern Energy Company's subsidiary Nekota Resources.

The Nekota pipeline was constructed in 1996 and was used to transport gas received from Northern Border Pipeline to Aberdeen, South Dakota.

I'm recommending that the charges passed through the PGA be reduced to a level that reflects Nekota's cost of providing the capacity. I also recommend that this adjustment be made effective retroactive to December 1996 when the costs were first passed through the PGA. The annual adjustment, which is based on Nekota actual investment in the transmission line, would reduce Northwestern Public Service's ongoing PGA collections by $403,185.

Q. Before you you have what's been marked as Exhibit A.

A. Yes.

Q. Do you have that?

A. Yes.

Q. Could you tell us what that is?

A. It's our calculation of the adjustment to the current rate paid by Northwestern Public Service to NEC.

Q. Do you want to kind of walk us through that?

A. Yes. In this calculation, the top line rate of return reflects the settlement rate of return as accepted in the settlement in this case. Federal income taxes are self-explanatory. The service period for the calculation is 20 years based on the contract in effect between Nekota and NEC.

Property taxes in this exhibit are the actual 1998 property taxes. The cost determined is subtracted from the current rate to yield the adjustment that we propose.

Q. Okay. There's been a lot of discussion of the various transactions involved here with the distribution system and that. Could you explain that a little more fully, please?

A. Yes. Northwestern Public Service's gas supplied to Aberdeen enters a distribution system through two pipelines. One is the preexisting

connection to Northern Natural. The other is a pipeline owned by Nekota Resources, Incorporated, a subsidiary of NEC and thereby an affiliate of Northwestern Public Service. Nekota is connected to the Northern Border Pipeline.

NEC entered into a contract with Nekota dated November 1st, 1996, whereby Nekota provides transportation service to NEC. By separate contract effective on the same date, Northwestern Public Service entered into a transportation services agreement with NEC. The rates on the two agreements are the same.

The contracts are for an initial term of ten years, but only the contract between Nekota and NEC is renewable by mutual agreement for an additional ten years. Northwestern Public Service's entitlement represents 62.5 percent of the capacity of Nekota's pipeline. For this it pays $48,000 a month, or $576,000 per year, all of which is assigned to South Dakota Gas Operations.

MS. CREMER: Before I forget, I would offer Exhibit A.

MS. WIEST: Any objection?

MS. WIEST: If not, it's admitted.

MR. DIETRICH: No objection.

Q. Is this a reasonable charge, Dave, the 48,000

per month?

A. No. This greatly exceeds the affiliate Nekota's cost of providing the service. Nekota's investment in the pipeline is $1,185,000. For such an investment an annual rental of $576,000 is excessive on its face.

But combining this with the facts that the facility has an expected life of at least 20 years, that only 62.5 percent of the capacity of this line is committed to Northwestern Public Service, and that by separate agreement Northwestern Public Service is obligated during the first five years of its contract to pay all its inspection costs and operation and maintenance expenses, makes this abundantly clear that the charge is excessive, unreasonable, and unjustified.

Moreover, while the contract requires payments from Northwestern Public Service are more than sufficient to pay for the entire line, the contract leaves 37.5 percent for the capacity uncommitted and available to NEC, the company's energy marketing affiliate, for generating additional profits.

Also, the fact that NEC's contract with Nekota is renewable for an additional ten years while the Northwestern Public Service contract with NEC is

not leaves open the possibility that after the ten-year term of the contract, Northwestern Public Service will not be able to use the Nekota pipeline at all, or at a reasonable cost if the market for gas transportation provides more lucrative opportunities for NEC.

Q. On Exhibit A, the adjustment that you recommended, the 403,185 -- strike that. Dave, why did you assign the entire Nekota pipeline cost of service to NWPS when Nekota and NEC have not committed the entire capacity of the line to NWPS?

A. Formal contracts notwithstanding, the company has represented that the entire capacity of the line will be available to Northwestern Public Service when it is needed, as the company stated earlier, even though Northwestern Public Service is able to use the capacity in excess of 15,000 MMBtu per day. Meanwhile any capacity unused by Northwestern Public Service is available to NEC for sale to others.

Q. Why are you recommending that the company be required to refund amounts collected since December of '96?

A. Charges imposed on Northwestern Public Service by its affiliate are grossly excessive and have been so since they were first flowed through the PGA in December of 1996. This has resulted in substantial

overcharges to Northwestern Public Service's gas customers in South Dakota.

Moreover, the effects of this less-than-arms-length transaction were introduced into Northwestern Public Service's PGA calculations without special notice by the company, and continued to be identified in those filings without reference to Nekota Resources or Northwestern Energy, but as NBPL-Aberdeen capacity.

Use of the semiautomatic pass-through mechanism in this manner is not appropriate, in my opinion, and an order requiring refunds with interest is justified.

Since the collections will have taken place over a period of nearly three years, I recommend the principal amount of the overcharges, together with accrued interest, be flowed back to rate payers over a three-year period in the PGA.

Q. Is that adjustment calculated in the same manner as a traditional rate case calculation?

A. No, it is not. In this case we have proposed a fixed monthly charge based on a 20-year contract life as opposed to a calculation based on the physical life of the pipe. This, in part, reflects ownership by the affiliate as opposed to ownership by Northwestern

Public Service.

Q. Mr. Hitchcock discussed a number of benefits that he claims NWPS's customers have received as a result of their building this pipeline. Do you dispute that these benefits may have taken place?

A. No.

Q. Assuming for the sake of argument that these benefits have occurred, would your proposal -- would your proposed adjustment affect any of these benefits?

A. No, not in my opinion.

Q. And let's discuss the PGA issue and when we first knew about that. When was the first you knew about this issue, Dave?

A. When Martin Bettmann instructed me during this rate case of investigation he was doing with pipeline facilities or affiliate transactions with our consultant, Mr. Towers.

Q. Do you know when the format of the tariffs changed?

A. Yes. It was during, as the company alluded to, it was NG96-015.

Q. I'll hand you what's been marked as Exhibit B, if you could identify that, please.

A. This was a PGA filing made just prior to the format change in tariff.

Q. And what's the date on that?

A. November -- it's dated by the company on November 4th, 1996.

Q. And what's our stamp date on there?

A. It was received by the Commission November 5th, 1996. And the effective date of the tariffs, the proposed effective date is November 1st, 1996.

Q. Do you normally review the PGA filings that are filed with the Commission?

A. Yes, I do.

Q. Does anyone else normally review them?

A. On occasion prior to this with the former employees that were with the Commission, there were times when we would do it for each other. Primarily I was responsible for review of the PGA.

Q. And as far as you know, you reviewed this PGA filing in Exhibit B?

A. Actually there were several staff members that worked on that docket, but I do as a matter of course review all the PGA filings.

Q. Okay.

MS. CREMER: I would offer Exhibit B.

MS. WIEST: Any objection?

MR. DIETRICH: Could I -- I'd like to ask a couple questions.

MS. WIEST: Go ahead.

MR. DIETRICH: How does this particular filing then relate to Exhibit 5, the data request response? Was Exhibit 5 information that was provided after this filing was made?

A. I think Exhibit 5, if I'm correct, is the next PGA. I believe it was the one in that PGA you have there the NBPL charge does not show up, and that filing it was done under the old format, the old tariff format.

MR. DIETRICH: Okay. As part of NG96-015, then, before that order was entered, the other data request and other information was received by you?

A. I would have to check to be sure. It should be stamped with a received date.

MR. DIETRICH: Perhaps you can compare the dates on Exhibits 5 and 6.

MS. CREMER: Is this to an objection to the exhibit or is this cross-examination of the witness?

MR. DIETRICH: I think -- well, it probably is a little of both. But I'm primarily trying to see if this exhibit itself accurately reflects the information that was present, but I can perhaps do that through cross-examination.

MS. CREMER: The purpose of that was merely

to show the old format of the tariff.

MR. DIETRICH: Okay.

MS. WIEST: Is there any objection to Exhibit B?

MR. DIETRICH: No.

MS. WIEST: Exhibit B is admitted.

MS. CREMER: Thank you.

Q. I'll show you what's been marked as Exhibit C. Could you identify that for us, please?

A. This is the cover letter of the PGA filing for the month after the exhibit just entered.

Q. And so it's the cover letter to Exhibit 5; is that correct?

A. Yeah, if you want to put it that way, yeah.

MS. CREMER: I would offer Exhibit C.

MR. DIETRICH: Just one clarifying question. As I understand it, Exhibit 5 was not the tariff filing, but it's responses to a data request related to a tariff filing, so --

MS. CREMER: Oh, it's not, okay.

MR. DIETRICH: It's not necessarily what accompanied Exhibit C; correct?

MS. CREMER: Okay, in that case.

A. I believe Exhibit 5, if I understand the company correctly, was an example of a PGA filing. It

wasn't the actual next month PGA filing.

MS. CREMER: It's Exhibit C of Exhibit 5 remember, your Exhibit C. You had two of them in 5. It's the cover letter to the first Exhibit C.

MS. WIEST: Exhibit 5.

MS. CREMER: In Exhibit 5.

MS. WIEST: This is Exhibit C. Is there an objection then, Mr. Dietrich?

MR. DIETRICH: No.

MS. WIEST: Then Exhibit C has been admitted.

Q. On that Exhibit C, Dave, is there any discussion in it regarding the Nekota pipeline?

A. No.

Q. Is there any indication or was -- did the company call you or give you any indication to look for a new line item in that PGA?

A. No.

Q. When you review the PGA's, what do you typically look for?

A. Usually make a comparison between the old PGA and the new PGA and look for something that would be under our jurisdiction or questionable change.

Q. Okay. Did you at any time discuss that Nekota pipeline during this time period December of '96

with Tom Hitchcock?

A. No.

Q. Or anyone from the company?

A. No.

Q. Did NWPS notify you in any manner whatsoever that the pipeline charge or a transaction with an affiliate was now showing up on the PGA tariff?

A. No.

Q. Were you present at the spring meeting that Rod Leyendecker testified to here earlier?

A. Yes.

Q. At that time -- and I think Mr. Leyendecker already told us he didn't jump on the table and announce it. But did he in any manner talk about the Nekota pipeline, to your recollection?

A. There was no mention of an affiliate pipeline and associated costs being put through the PGA or any affiliate transactions going through the PGA.

Q. Is there any correspondence in docket NG96-015 or any PGA filing that ever mentioned an affiliate transaction?

A. No.

Q. Have other companies notified staff of PGA changes?

A. Certainly.

Q. And how do they normally do that?

A. Normally it's right in the cover letter. I currently have a filing for Montana-Dakota Utilities on my desk right now that discusses a demand reassignment. It's quite common.

Q. Regarding staff's review of the PGA's, when did NWPS file a December 1996 PGA? What was the date on that, do you know? I think that's Exhibit C.

A. It was filed with the Commission on December 4th.

Q. And what was the effective date of that? What was their proposed effective date?

A. I don't know if I have that.

Q. It would be on Exhibit C of Exhibit 5. I'll help you here, Dave. On the cover letter Exhibit C, does it give an effective date in the cover letter?

A. Yeah, effective December 1st.

Q. 1996?

A. Yes.

Q. Did you review NWPS's last 12-month PGA filings?

A. Yes.

Q. And is that same scenario true that you just laid out for us, they file after their proposed effective date?

A. Yes.

Q. And on how many times in the last 12 months did that happen?

A. 12.

Q. So 12 out of 12?

A. Yes.

Q. In your opinion, Dave, had another contractor built the line, or if NWPS owned the line, would the benefits that Mr. Hitchcock referred to be the same or better?

A. Yes.

Q. Would they be the same or better?

A. Well, it's hard to say that they would be better or the exactly the same. It depends on -- I would say that if another contractor had built a line, at least there would be the opportunity for a competitive bidding process to take place whereby the charge for the capacity of the line itself may well have been cheaper.

MS. WIEST: That's all I have at this time.

MS. WIEST: Cross?

CROSS-EXAMINATION

BY MR. DIETRICH:

Q. Just getting back to that point, if another person owned -- or built and owned this line, would

normally that Northwestern been able to contract for 15,000 MMBtu and have access to 100 percent of the capacity of that line on any date they want, or would that would they have to pay for the full capacity?

A. Well, certainly on a contract to build like that would be dependent on the negotiations that took place. Presumably Northwestern Public Service could retain full capacity rights to the entire line.

Q. Paying for what you call 62 and a half percent of it?

A. Well, actually my adjustment would reflect that they would purchase 100 percent of it.

Q. But you just indicated someone else could have purchased this and sold capacity for approximately the same amount.

MS. CREMER: Was that a question or a statement?

Q. Is that what you just said?

A. I'm saying that if an alternative person had constructed and owned the line, your rate cost to Northwestern Public Service may well have been lower than 3.20.

Q. Could I have you look at Exhibit 3, please? You heard Mr. Hitchcock's testimony about the benefits and you indicated just now in your testimony that even

given your rate treatment, all of those benefits would have been present for Northwestern Public Service; correct?

A. I didn't say they would. It would have been possible they would have. No, I can't say that they wouldn't have.

Q. Your Exhibit A essentially only -- through Exhibit A the only payment that Northwestern makes is a return for the pipeline on the pipeline costs themselves?

A. That's correct.

Q. There's no recognition of any other benefits that Northwestern Public Service receives through the transactions that its affiliates made with Northern Natural; correct?

A. There's no recognition of expenses other than for that particular pipe facility, yeah.

Q. Okay. So the opportunity to utilize Northern Natural capacity elsewhere -- or to use other capacity other than Northern elsewhere and the value that that may have to Northwestern Public Service's system is not included in your Exhibit A?

A. That's correct.

Q. The value that allowing improving peak day pipeline capacity other than the purchase of this

particular piece of capacity provides to Northwestern is not reflected?

A. That's correct.

Q. The improvement of the pressure situation is not reflected other than what that piece of pipe is providing?

A. That's correct. Everything in my exhibit refers to that particular facility itself.

Q. Okay. So the reassignment of delivery point capability throughout Northwestern's system, including the ability to change that delivery point capability and avoid the types of point-to-point penalty charges that Mr. Hitchcock testified, is not reflected in Exhibit A?

A. That's correct, and I wouldn't necessarily assign it to that facility --

Q. Okay.

A. -- as a rate for that just that particular facility.

Q. Okay. But it is a benefit -- excuse me, I'll go on. And the ability to reduce the essentially stranded TFF capacity in the field and have market area capacity to serve Northwestern's customers system-wide is not reflected in Exhibit A?

A. That's correct.

Q. And the ability to increase margins for Northwestern Public Service by having increased potential sales to interruptible customers through these other capacity improvements is not reflected on Exhibit A other than what the pipeline facility itself provides?

A. That's correct.

Q. Okay. Would you agree that all of these project benefits are to the benefit of Northwestern Public Service customers and that there is a value that they have received from this project and that various negotiations that have taken place with Northern Natural?

A. I'm not sure that I can agree that they've been -- those benefits have come across come about as a result of this particular project.

Q. Well, if Northwestern had not changed the arrangement with Northern and gotten the various changes in its obligations, which I think are reflected in Exhibit No. 8, which is that kind of letter agreement that summarizes the Northern Natural changes?

A. Right.

Q. If it had not had those, if it had not completed that negotiations with Northern, these various benefits that Mr. Hitchcock talked about would

not have been available for Northwestern Public Service customers; correct?

MS. CREMER: I would object. That would be speculation on Mr. Jacobson's part.

MR. DIETRICH: Well --

MS. CREMER: You've got to get a ruling first.

MS. WIEST: Overruled.

A. Well, I'm not -- the benefits that Mr. Hitchcock talks about can be quantified to my satisfaction. I mean I hate to go through the whole list and say yes or no which one can be quantified and how material each alleged benefit is. At least one or two of those I'm highly in support of.

Q. Which ones are they?

A. If assuming there were benefits? Could you repeat your question again.

Q. Go ahead. I interrupted you, sorry. Finish your answer and I'll ask another question.

A. I can't remember what the question was.

Q. I guess my question is you said some of these you feel support these benefits.

A. Yes.

Q. Which ones?

A. Well, I'm not completely -- I don't

understand the capacity release one, to start with. It appears to me that, first of all, I would measure capacity by volumes and not by dollar amounts because the company themselves admitted the price of released capacity fluctuates, can fluctuate greatly. If the amount of capacity actually released is more indicative of a possible effect of the pipeline.

However, multiple weather conditions, all kinds of things can affect the availability of released capacity. The exhibit itself shows that the exhibit itself shows after the pipeline was constructed that there was a decrease from -- decrease of dollars of capacity released from the prior year.

Q. For a few isolated months, I believe, is the exhibit; correct?

A. Several of the months.

Q. But the overall number at the bottom of the page was significantly higher?

A. Again, it's a dollar amount and not a volume amount. It doesn't indicate the amount of capacity released.

Q. Okay. But do you recall Mr. Hitchcock also testified that for every year since this pipeline has been put in place the dollar amount has been 200,000 or greater?

A. I heard something to that effect. I can't recall exact amount.

Q. And wouldn't doing this in terms of volumes necessarily give you less than the full picture because you may release it for a very small value, whereas the true measure of the value is what are the total dollars that you are able to get from releasing it?

A. With regard to value, you're right, but with regard to the pipeline creating the availability of released capacity and the capacity is measured in volumes.

Q. Turning to the PGA filings that Northwestern has made, whether it's 35 or 36 monthly filings that have been made by Northwestern since the time that this entry has gone in, you have reviewed each one of those filings?

A. Yes.

Q. An entry of $576,000 that hasn't appeared in a prior PGA filing would not have raised a question, or did not raise a question in your mind where you would have called the company and asked them to provide backup data for that?

A. It didn't in this case because it's being labeled as Northern Border Pipeline. It was my call that it was an interstate transportation or interstate

pipeline rate tariffed by the FDRC and it was not subject to our jurisdiction. I also thought that any transaction like that that would be an affiliate transaction would have been communicated by the company to the staff.

Q. You stated that Northwestern has traditionally filed in the last 12 months its filings after the first of the month?

A. That's correct.

Q. Is that primarily because it's based on information for the prior month?

A. Yes.

Q. Is there any -- do you feel that there is any unnecessary delay in them getting that information to you?

A. If I thought that I would have complained already. I was responding to the allegation that the company is making that staff should respond within ten days of every -- now, I don't know whether it's the effective date or the file date and respond by that time and have absolutely no recourse to go back and correct situations that it finds after that period of time.

Quite commonly when I find something, an aberration or a correction necessary in a PGA, just the

data request itself to understand the situation could well take longer than ten days to receive.

Q. Okay. But during this period of time you never made any kind of a request that you wanted further information from the company --

A. I can't recall.

Q. -- on this issue?

A. Not on this particular line item.

Q. Do you recall -- getting to the April 1997 presentation, do you recall at all what was said with regard to that corporate structure slide that --

A. I recall several of the conversations. Specifically, I recall Mary Lewis speaking about getting back into appliance repair and sales and insurance type policies and such as that. It had -- all it had to do with your diversification of your corporate structure.

Q. You don't recall specifically what Mr. Leyendecker said?

A. If I recall it correctly, he -- kind of the whole meeting was in general -- I would define it as a dog and pony show -- but informational meeting of a general nature regarding the current corporate activities of the company.

Q. So speaking as one of the dogs or ponies that

made a presentation at that meeting, would you characterize it as kind of a general informational meeting about what the company was doing and changes it was making?

A. Yes. In fact, I'm one of the few people in the Commission that kept the entire brochure of what you have handed out, which goes through every presentation made, along with the book, and I have it here with me today.

Q. Are there any specific Commission rules with regard to PGA filings as to what format it should have or what should be disclosed that you're aware of?

A. No, not to my knowledge. It's a tariff matter.

MR. DIETRICH: I have nothing further.

MS. WIEST: Commissioners?

CHAIRMAN BURG: I have a couple. Dave, if you had pulled Exhibit 3 of Northwestern Public Service or Northwestern and Exhibit A of yours for comparison of the two. If I looked at that right, the major difference I see is you've disallowed the entire $588 dollar, which has now been simplified as a settlement amount agreement; is that correct?

A. That is correct. That expense, as you probably understood through this conversation today, is

not what I would consider a direct expense of this pipeline and the rate that normally would come from operating a facility.

CHAIRMAN BURG: I understand that, but should the 588 be a recoverable charge?

A. That I would have to see support for more than I've seen.

CHAIRMAN BURG: If it were determined that it was a recoverable charge, would the bottom line be any different?

A. If there were --

CHAIRMAN BURG: For the company?

A. If there were a proper purchased gas adjustment charge, it would be -- it would flow through the PGA.

CHAIRMAN BURG: Right. So the actual end result would not be that much different?

A. That's correct. Our calculation would compare to the 165, 23 and the 48.

CHAIRMAN BURG: So would it be accurate to say the difference between the way they have -- your exhibit only goes through recovering the cost of the pipeline itself; is that correct?

A. That's correct.

CHAIRMAN BURG: And their exhibit includes

the recovery of the settlement agreement as such, and at this time you have not had sufficient data to know that that settlement agreement should be a recoverable charge? I don't want to put words in your mouth.

A. Yeah, exactly, yes.

CHAIRMAN BURG: That's all I have.

MS. WIEST: If you look at Exhibit 3, they have stated project costs that administrative costs charged are $48,000.

A. Yes.

MS. WIEST: Did you state that you thought those were too high?

A. No, I didn't state that they were too high. They were just, as of yet, they've been unsupported. It was just a $4,000 a month flat fee without cost support for it. It could be reasonable.

MS. WIEST: So you don't know if that's reasonable or not because you haven't seen any support for it?

A. Right. It's not based on any cost. It's a $4,000 flat fee.

MS. WIEST: Now, staff's calculation of the pipeline costs, that did not include that $588,000 identified in Exhibit 3 which is characterized as a payment to Northern Natural; is that correct?

A. That's correct.

MS. WIEST: And why don't you think that's -- what is your understanding of what that 588,000 is for?

A. My understanding is that the way the company has explained it, is that was a payment for other capacity obtained from Northern Natural Gas as well as a payment to get out of the contract restriction that limited the company from getting capacity from other sources other than Northern Natural Gas. That, in other words, it's a buy-out and a purchase of other capacity.

MS. WIEST: And you cannot break it down as to what portion of that is actually a buy-out and what is the payment for capacity?

A. That hasn't -- we haven't received that information yet, no.

MS. WIEST: And then do you know what do the 588,000 give Northern Natural that they wouldn't have got otherwise?

A. How much?

MS. WIEST: What do the 588,000 give Northern Natural Gas that they wouldn't have gotten otherwise, do you know? I asked the same question.

A. I don't know that at this time.

MS. WIEST: And then I believe you said --

and correct me if I'm wrong. You said that the actual contract, which I haven't read yet, provides for 62.5 percent capacity to NPS; is that correct?

A. Well, I don't have that in front of me.

MS. WIEST: But I believe you mentioned the 62.5 percent. Was that based on an amount that was contained in the contract, the actual contract?

A. I don't recall the actual contract. I recall the information that the company provided stating that it was 62.5 percent, or 15,000 MMBtu capacity was available or reserved, or you know they have dedicated to Northwestern Public Service.

MS. WIEST: So that's information that staff was given, but then later it was represented to you that they actually had access to 100 percent of that capacity and that's why you assigned 100 percent of those costs to NPS?

A. Yeah. We understood that the -- actually it could be 100 percent available given that NEC or no other party was accessing any of the capacity there. However, it is available for use by others. So it's not necessarily 100 percent available. It's available to the extent it's not used by NEC or other third parties.

MS. WIEST: That's all I had. Any redirect?

REDIRECT EXAMINATION

BY MS. CREMER:

Q. Mr. Dietrich asked you about if there was anything in the rules about a PGA and you said it's the same as to that tariff?

A. The rules governing each PGA for each company are spelled out in the tariff. Each PGA is calculated differently. The support for each PGA changes different with each company that comes in. So that makes it more detailed than others.

MS. CREMER: Thank you.

CHAIRMAN BURG: Dave, if that remaining 32, 38 percent capacity, which is a percentage -- I don't want to dwell on it. But if the remaining amount -- in other words, the way I understand the contract is they're only using 62 percent; they have the availability of the hundred percent. They could call that up at any time that they had the need for that.

If NEC, though, for example -- and when that was not being used by Northwestern, if NEC sold that capacity to anybody else, would they then come under a different type of regulation as a merchant as a pipeline company?

A. That may call for a legal conclusion. But it would be my thought that if somebody other than --

well, if somebody other than an affiliate of the parent company, as the statute -- in other words, if an unaffiliated third party was a customer of that pipeline, then all of the rates under that pipeline would become under the jurisdiction of the Commission, including Northwestern Public Service's and everybody's. I'm not a lawyer so...

CHAIRMAN BURG: Okay. That was the question I had. That's all.

MS. WIEST: Any other questions? If not, do you have any other witnesses?

MS. CREMER: No, I do not.

MS. WIEST: Do the parties have -- did you have any rebuttal witnesses?

MR. DIETRICH: No, I don't believe so.

CHAIRMAN BURG: Then my question is do the parties wish to make closing statements, or are any of the parties requesting that this be briefed?

MR. MOLSTAD: I'd certainly make a closing statement.

MR. DIETRICH: I think there are some legal issues here so it may be appropriate to prepare briefs in this matter. I think we've talked about statutes, we've talked about tariffs, we've talked about rules. I think it might be appropriate to prepare short briefs

on some of the matters that have been raised as well.

MS. WIEST: Since we're on that subject, let's go off the record.

(A DISCUSSION WAS HELD OFF THE RECORD.)

MS. WIEST: We'll go back on the record. The briefing schedule will be NPS will file their initial brief December 1st, staff January 7th, and an optional rebuttal by NPS January 21st. And at this time we'll have closing arguments. NPS.

MR. MOLSTAD: Thank you. Thank you. It's been a long day so I'll try to be short.

I would like to summarize the Northwestern Public Service's opinion in that matter. Thank you very much for your time and consideration to everybody here. I know at times it may have seemed to be confusing as far as the transaction and other matters but maybe I'll try to just summarize this as best I can. Because I think what we want to do here is look at, you know, what's the bottom line benefit to the customers, and that's the important aspect of this.

Northwestern Public Service, NEC, had a problem that they saw that was going to affect the customers because of the Northern Natural Gas loop situation, lack of pressure of capacity, which was going to put Northwestern Public Service's customers in

a bind potentially. They sought alternatives to that.

They have went to Northern Natural. Northern Natural would not help them at that time. They felt that it wasn't maybe that important. Maybe felt they would wait to try to rectify that situation.

However, Northwestern Public Service in working with NEC certainly couldn't wait that long so they tried to come up with a creative way to help NWS's customers. So they tried to negotiate with Northern Natural.

Northern Natural could not -- I think it's important to note they could not lower their rates, the maximum rates, because of this most favored nations contracts or clauses in on the contract. If they did that, they would have to lower the charges to its other contract parties, which could be result in substantial loss of dollars to Northern Natural.

So in trying to rectify the situation, a method came about which would solve the capacity problems for Northwestern Public Service's customers.

One of the big stumbling blocks, of course, was the contract provision with Northern Natural that made NPS only use Northern Natural system. So what to keep in mind here that what has happened is that Northwestern Public Service, NEC, put together its own

pipeline. Because of that pipeline, the costs to the NPS customers was reduced almost in half.

Yes, there were costs incurred. I mean there were costs incurred, project costs of Mr. Hitchcock has alluded to that came about because of this negotiated agreement. Sure, you might say, yeah, we could have gone and litigated that issue, but, you know, who knows. I mean very expensive. You never know the outcome.

So what do you do is you try to do what you think is best for your customer. And so that was a solution that came up. I believe you heard Mr. Hitchcock testify that the project costs, but also the project benefits of the cost of $576,000 PGA costs versus over one million dollars under the original scenario if that were in place.

So I think it boils down, you know, to that. I mean could NPS have gone to some other pipeline company? Who knows. There's no testimony in the record that says they would have saved any money. I think the big issue is they did save the customers that amount of dollars, plus, you know, were able to get the capacity, at least credits which offset the PGA cost to the customers, plus they also had the other benefits that Mr. Hitchcock alluded to.

So it's easy to second-guess, but like Rod Leyendecker said -- you heard him here. That, hey, they were out to do what they could for the customers. And the deal came about in the attempt to do that.

They talk about, you know, the charges are grossly unfair. There's been testimony from the staff. But those grossly unfair charges that have been talked about are really cost incurred for services paid to Northern Natural. Those were the costs that were incurred by this transaction.

As Mr. Hitchcock has laid out in his exhibit, those are costs. Now, that's just the costs that came out of the transaction. So they were project costs, and you have to look beyond what the pipeline costs.

What did the pipeline cost? Comments were made that, hey, 5.5 million dollars return on a one million dollar investment. But also look at that which is the whole thing because you've got all these other benefits. But more than that, what would the costs had been to the consumer if this would not have been done? You heard that probably would have been an extra five million dollars in costs, ten years times 576,000.

You heard Mr. Hitchcock talk about, you know, the process and how this PGA went through. And there doesn't seem to be any rules as far as, you know, what

you have to do when you file your PGA. Certainly Northwestern Public Service is not trying to hide anything.

Mr. Leyendecker testified at the new structure and informational presentation to the Commission and talked about Nekota. He talked about -- you know, he would have talked about was the fact that Nekota was there to build a pipeline. It's the only pipeline they've ever built. So certainly you don't know what they said.

But when you put that together with the fact that the PGA has been filed the way it has been, there haven't been any objections, it wasn't outlined maybe specifically as maybe would have helped in this case. That can be done different. That's fine. We would be glad to work with that. But not having any specific guidelines to go by, Northwestern Public Service did what they thought was best for the customer, and that resulted in where we're at today.

Again, we would state that the $576,000 is reasonable based upon costs, and the pipeline saved the customers a lot of money. We would object to the refund that Mr. Jacobson talked about. We don't feel that is excessive to begin with because of the fact we saved the consumers so much money in the long haul.

But certainly there wasn't any intent to hide anything but just the opposite. Therefore, we would feel that even though they were filed maybe a day or two after the beginning of the month and new PGA tariffs, that they were never challenged, never even questioned.

And, therefore, I guess in summary, we feel like they are justified and that they should continue as they are and that there should be no refund, no adjustment to the PGA cost and further PGA monthly filings.

MS. WIEST: Thank you. Ms. Cremer.

MS. CREMER: Thank you. The issue here goes to the recovery of charges, to the recovery of the pipeline charges and all those other costs shouldn't be included.

NWPS can apologize for not being more forthright, but the fact remains that nowhere in any PGA do the words Nekota Pipeline appear. It was placed in the PGA without the staff's knowledge or Commission approval, and therefore there should be a refund of $1,297,000 -- let me try again, of approximately $1,297,387. Thank you.

MS. WIEST: Thank you. That will close the hearing. (THE HEARING CONCLUDED AT 4:37 P.M.)

STATE OF SOUTH DAKOTA)
)
COUNTY OF HUGHES)

I, LORI J. GRODE, Registered Merit Reporter and Notary Public in and for the State of South Dakota:

DO HEREBY CERTIFY that the above hearing, pages 1 through 169, inclusive, was recorded stenographically by me and reduced to typewriting.

I FURTHER CERTIFY that the foregoing transcript of the said hearing is a true and correct transcript of the stenographic notes at the time and place specified hereinbefore.

I FURTHER CERTIFY that I am not a relative or employee or attorney or counsel of any of the parties, nor a relative or employee of such attorney or counsel, or financially interested directly or indirectly in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and seal of office at Pierre, South Dakota, this 27th day of October 1999.

Lori J. Grode, RMR, RPR

NORTHWESTERN PUBLIC SERVICE

Exhibit___(TPH-3)

February 1, 1996 System Peak Day Information
Summary of All Customer Usage
Volumes in MMBtu

SENDOUT AND COMPARISION TO PRIMARY FIRM PIPELINE CAPACITY

Location	NNG Primary Firm MDQ	Total Sendout	Third Party Sendout	NWPS Sendout	NWPS Sendout Over NNG Firm MDQ
Aberdeen #1	10,358	19,500	0	19,500	9,142
Mitchell #1	4,715	10,869	0	10,869	6,154
Brookings #1	4,939	9,150	672	8,478	3,539
Huron #1	7,390	10,700	46	10,654	3,264
Madison #1	1,900	4,400	0	4,400	2,500
Redfield #1	865	2,256	0	2,256	1,391
Bryant #1	153	1,336	0	1,336	1,183
Volga #1	254	957	0	957	703
De Smet #1	445	1,017	0	1,017	572
Clark #1	365	910	0	910	545
McCain Foods	300	698	0	698	398
Howard #1	365	750	0	750	385
Arlington #1	309	611	0	611	302
Lake Preston #1	210	498	0	498	288
Alexandria #1	178	356	0	356	178
Frankfort #1	50	191	0	191	141
Doland #1	120	243	0	243	123
Conde #1	77	174	0	174	97
Willow Lake #1	133	229	0	229	96
Oldham #1	77	134	0	134	57
Yale #1	17	64	0	64	47
Spencer #1	123	155	0	155	32
Farm Taps/Misc.	0	26	0	26	26
Hazel #1	50	74	0	74	24
Raymond #1	30	51	0	51	21
Turton #1	50	70	0	70	20
Vienna #1	27	46	0	46	19
Parker #1	2,163	972	21	951	(1,212)
Parkston #1	3,602	2,195	0	2,195	(1,407)
Webster #1	3,605	1,626	0	1,626	(1,979)
Milbank #1	6,413	3,921	0	3,921	(2,492)
Totals	49,283	74,179	739	73,440	24,157

SENDOUT AND CAPICITY SOURCE

Description	Total	Firm	Interruptible
NWPS Customer Sales	71,207	59,582	11,625
3.04% Dist. Use and Loss	2,233	1,868	365
NWPS Sendout	73,440	61,450	11,990
Source of Capacity:			
NNG Primary Firm	49,283	49,283	0
NNG Secondary Firm	20,434	8,444	11,990
NWPS Peak Shaving	3,723	3,723	0
Total Capacity Source	73,440	61,450	11,990

NWPS CUSTOMER SALES

Rate 84 Firm Tariff Sales	3,265	3,265	0
Rate 88 Firm Agency Sales	539	539	0
Rate 84 Overrun Tariff Sales	2,006	0	2,006
Rate 88 Overrun Agency Sales	2,077	0	2,077
Rate 85 Inter. Tariff Sales	2,498	0	2,498
Rate 89 Inter. Agency Sales	5,044	0	5,044
Rate 81/82 Firm Tariff Sales	55,778	55,778	0
Total Customer Sales	71,207	59,582	11,625

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EXHIBIT

NG99-002

CONFIDENTIAL

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EXHIBIT
3

NORTHWESTERN PUBLIC SERVICE
SUMMARY OF NEKOTA PIPELINE PROJECT

PROJECT COSTS

Capacity costs from Northern Natural for firm transportation and deferred delivery service	$588,000
Pre-tax return on Aberdeen pipeline	$165,000
Property taxes on Aberdeen pipeline	$23,000
Administrative costs for regulatory review, balancing, nominations and procurement on Northern Border	$48,000
Total Project Costs	$824,000

COST RESPONSIBILITY

	Cost		Pipeline Capacity	
	Dollars	%	MMBtu	%
NorthWestern Public Service	$576,000	70%	15,000	70%
NorthWestern Energy	$248,000	30%	6,500	30%
Total Cost and Capacity Responsibility	$824,000	100%	21,500	100%

(As compared to traditional NNG capacity cost of $6.65 per MMBTU times 15,000 mmbtu times 12 months = annual cost of $1,197,000.)

PROJECT BENEFITS

	NPS Customers	NEC Customers
1. Remove restriction of exclusive NNG supply	Yes	Yes
2. Peak day pipeline capacity	Yes	Yes
3. Reliability (pressure at Aberdeen)	Yes	Yes
4. Reassignment of delivery point capacity	Yes	No
5. Field capacity (TFF) turnback and conversion to market service	Yes	No
6. Released Capacity Credits	Yes	No
7. Ability to maintaint interuptible customers even on peak days.	Yes	Yes

WARNER LINE BENEFIT TO
NORTHWESTERN UTILITY OPERATIONS
Additional Northern Natural Gas Firm Capacity Releases

Exhibit___(TPH-5)

Production Month	Capacity Release Credits	Production Month	Capacity Release Credits	Capacity Release Benefit
Nov. 96	$43,486.97	Nov. 95	$2,042.07	$41,444.90
Dec. 96	$36,332.87	Dec. 95	$4,184.72	$32,148.15
Jan. 97	$28,405.72	Jan. 96	$7,897.21	$20,508.51
Feb. 97	$39,113.98	Feb. 96	$5,713.38	$33,400.60
Mar. 97	$34,859.08	Mar. 96	$9,136.32	$25,722.76
Apr. 97	$70,254.79	Apr. 96	$7,210.71	$63,044.08
May 97	$39,260.83	May 96	$9,084.32	$30,176 51
Jun. 97	$15,393.08	Jun. 96	$24,411.42	($9,018.34)
Jul. 97	$8,752.99	Jul. 96	$22,535.79	($13,782.80)
Aug. 97	$3,652.59	Aug. 96	$11,038.79	($7,386.20)
Sep. 97	$11,452.10	Sep. 96	$26,419.77	($14,967.67)
Oct. 97	$33,832.13	Oct. 96	$30,540.78	$3,291.35
Totals	$364,797.13	Totals	$160,215.28	$204,581.85

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EXHIBIT
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EXHIBIT

STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

STATE OF SOUTH DAKOTA)
) SS
COUNTY OF BEADLE)

ATTESTATION
DOCKET NG96-015

Thomas P. Hitchcock attests that he is Manager-Regulatory & Pricing Services of Northwestern Public Service Company and that the responses, including supporting working papers and data, to the August 9, 1996 PUC Staff data request are true and correct to the best of his information, knowledge and belief, and reflect the books and records of Northwestern Public Service Company.

Thomas P. Hitchcock

Thomas P. Hitchcock

Sworn and subscribed to before me
this 16th day of October, 1996.

Sharman K. Neitzert

Sharman K. Neitzert, Notary Public
Beadle County, South Dakota

My Commission Expires:

(SEAL)

NORTHWESTERN RESPONSES TO STAFF QUESTIONS AND/OR SUGGESTED CHANGES TO THE FILING FOR TARIFF REVISIONS, DOCKET NG96-015

Staff No. 1 - In Section 3, Sheet No. 3.1, paragraph 1. regarding applicability, change the word "on" to the word "of" in the second line.

Northwestern Response: Agree, see revision to tariff.

Staff No. 2 - In Section 3, Sheet No. 3.1, section 3. regarding rates, please add the words "of annual charge per month" after the percentages listed at the Seasonally profiled Gas Demand Payment Elections.

Northwestern Response: Agree, see revision to tariff.

Staff No. 3 - In Section 3, Sheets 3.2 and 4.1, please add language to the "Penalty Provision" section stating that costs collected will be credited to expense in PGA true-up filings.

Northwestern Response: Agree, see revision to tariff.

Staff No. 4 - In Section 3, Sheet 4.1 should be 5th Revised Canceling 4th Revised. Also the 4th line in the "Applicability" section should be revised by deleting the words "to it" and adding an "s" to the word "supplier".

Northwestern Response: Agree, see revision to tariff.

NORTHWESTERN RESPONSES TO STAFF QUESTIONS AND/OR SUGGESTED CHANGES TO THE FILING FOR TARIFF REVISIONS, DOCKET NG96-015

Staff No. 5 - In Section 3, Sheet 6.3, in the paragraph dealing with "Daily Balancing Limit" the 8th line should have the words "on a critical day" inserted after the word "imbalances". Also, provide a detailed explanation for the need to penalize positive imbalances on NWPS' system and a further explanation of the derivation of the reservation and commodity charges for Daily Balancing Service.

Northwestern Response: Agree on word change, see revision to tariff. There is a need to penalize positive imbalances on NWPS' gas system. First, too much gas coming into the system on a warm day can cause operational problems, almost as bad as when not enough gas is coming in on a cold day. Second, Northern Natural charges a variance charge for positive imbalances. Without a way to collect for these from transportation customers, NWPS' core customers could end up with charges from Northern that were not the result of any action by the LDC to cause such charges. The derivation of the reservation charges for Daily Balancing Service was shown on a worksheet previously provided Staff at the time of filing. It is attached as Exhibit A. In general, certain annual costs such as FDD, SMS, and peaking supply reservation charges were allocated to balancing services to derive a reservation cost. Using NNG market area capacity of 49,283 MMBtu, the cost works out to around $0.90 per MMBtu ($0.09 per therm) per month. In the revised tariffs, seasonally adjusted rates are proposed. The rate for the six winter months is proposed at $0.15 per therm, and $0.03 per therm in the six summer months (April - September).

Staff No. 6 -Regarding Group Balancing Service, must all customers within a group choose the same method of Retention? If so please state in the tariff.

Northwestern Response: It was our intent that all customers within a group choose the same method of fuel retention. Please see revision to tariff.

Staff No. 7 - In Section 3, Sheet 6.7, line 10 of paragraph (iii), the word "within" should be replaced by the word "upon".

Northwestern Response: Agree, see revision to tariff.

NORTHWESTERN RESPONSES TO STAFF QUESTIONS AND/OR SUGGESTED CHANGES TO THE FILING FOR TARIFF REVISIONS, DOCKET NG96-015

Staff No. 8 - Regarding the Extended Service Rider on Sheet 8 of Section 3, please provide cost of service justification for continuing this rate.

Northwestern Response: The only proposed change to this tariff sheet was changing the word "ccf" to therm. Attached as Exhibit B, is the cost of service justification for this service included in Rod Leyendecker's testimony in the last rate case proceeding.

Staff No. 9 - Section 3, Sheet 9, line 7 of the 1st paragraph, change the word "its" to "a". Also add one sentence to the end of the first paragraph which states, "However, in the case where a refund exceeds $300,000, the Company shall file a refund plan before the Commission and the Commission shall determine the method of refund." Also, add to the end of the second paragraph "All accrued over or under variances shall be assessed a carrying charge which shall be the overall rate of return allowed by the Commission in the Company's last general rate filing. Delete the 3rd paragraph. Also, add language to this page which addresses the treatment of revenues collected from transportation settlements of imbalances, over/under delivery charges for imbalances, additional charges collected for imbalances, transportation retention, rate 84 and 85 penalties and surcharges and any other similar revenues or costs.

Northwestern Response: Agree, see revision to tariff.

Staff No. 10 - Provide a sample PGA filing incorporating the effects of this filing with all supporting workpapers.

Northwestern Response: Please see attached Exhibit C.

Staff No. 11 - In Section 3, Sheet 11, regarding the proposed class distribution of manufactured gas plant removal costs, please provide significant evidence of the threat of bypass by Commercial and Industrial and Transportation customers.

Northwestern Response: Please see attached Exhibit D, which sets forth avoided cost economics for the largest bypass threats on the NWPS system in South Dakota. Northwestern is now proposing an equal gas plant removal cost surcharge rate for all customers. This was made possible by the use of a pragmatic adjustment to shift other non-gas supply costs amongst customer classes.

NORTHWESTERN RESPONSES TO STAFF QUESTIONS AND/OR SUGGESTED CHANGES TO THE FILING FOR TARIFF REVISIONS, DOCKET NG96-015

Staff No. 12 - In Section 5, Sheet 1, please delete the last sentence of section 4.

Staff No. 13 - In Section 5, Sheet 1a, please delete the last sentence of section 4.

Northwestern Response: Agree, see revisions to tariff.

Staff No. 14 - In Section 5, Sheet 6.2, section 7, explain in option one where these revenues will be credited to.

Northwestern Response: Northwestern proposes that these revenues are credited to expense in the PGA true-up filing, see revision to tariff.

Staff No. 15 - In Section 5, Sheet 6.3, section 9, explain how the order of deliveries for billing purposes is implemented under all possible scenarios. Also, section 10.(bb) refers to the FERC priority guidelines. Provide this priority schedule in the tariff.

Northwestern Response: The order of deliveries for billing purposes is as set forth in the tariff. If only two services are applicable, they are in the same priority order. In addition, we have added a new section on priority of service, Section 5, Sheet 5.2.

Staff No. 16 - In Section 6, Sheet 24.2, add the word "as" after the word "attached" in the second line of paragraph concerning Pricing.

Northwestern Response: Agree, see revision to tariff.

Staff No. 17 - Provide a history of the manufactured gas plant previously located in Huron including the dates of its operational life, who owned and/or operated it throughout its service life and which customers were served by its production.

Northwestern Response: Attached as Exhibit E, is information related to the manufactured gas plant in Huron. In general, natural gas customers were served by its production. The Staff asked for some removal cost breakdown. This information is also attached.

Exhibit A

NORTHWESTERN PUBLIC SERVICE COMPANY

Calculation of Market Rate for Supply Standby
and Balancing Services

Line No.	Supply or Balancing Service Component	Demand Charge	Months or Days*	Contract Demand MMBtu	Total Cost
	(a)	(b) $/MMBtu	(c)	(d)	(e)
1	Northern FDD Reservation	$1.4710	12	6,936	122,470
2	Northern FDD Capacity	$0.3062	5	80,000	122,480
3	Northern SMS Reservation	$1.7500	12	3,000	63,000
4	3 Month Supply Peaking/Swing Service	$0.1600	90 *	15,000	216,000
5	5 Month Supply Peaking/Swing Service	$0.1117	150 *	15,000	251,250
6	Peaking/Swing Commodity Premium				
7	plus Propane Peak Shaving Backup	$0.0800	150 *	15,000	180,000
8					
9					
10	Totals				955,200
11					==========
12					

Line No.	Supply or Balancing Service Component	NNG Market Area Capacity MMBtu/Day	Cost per Therm of NNG Market Area Capacity	Supply Standby Related	Balancing Related
	(a)	(b)	(c) $/Therm	(d) $/Therm	(e) $/Therm
13					
14					
15					
16					
17					
18					
19					
20	Northern FDD Reservation	49,283	$0.0207		$0.0207
21	Northern FDD Capacity	49,283	$0.0207		$0.0207
22	Northern SMS Reservation	49,283	$0.0107		$0.0107
23	3 Month Supply Peaking/Swing Service	49,283	$0.0365	$0.0183	$0.0182
24	5 Month Supply Peaking/Swing Service	49,283	$0.0425	$0.0213	$0.0212
25	Peaking/Swing Commodity Premium				
26	plus Propane Peak Shaving Backup	49,283	$0.0304	$0.0304	
27					
28					
29	Totals		$0.1615	$0.0700	$0.0915
30			==========	==========	==========
31					
32	100% Load Factor Rate		$0.0053	$0.0023	$0.0030
			==========	==========	==========

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Exhibit B

upon to provide service only during the few very coldest days of the year. A cost has to be assessed for this service so as to protect the balance of customers from having to bear these costs.

A second provision is the Extended Service Rider shown on Exhibit___(RFL-6). This proposed rider is to be applicable to large customers to help deal with competitive forces that are surely in our future. The rider will offer varying levels of discounts in return for agreeing to stay on Northwestern's system for extended terms. It is in the best interest of the Company, its customers, the Commission and perhaps all of South Dakota that these customers remain on Northwestern's system.

Q. Please elaborate on the proposed rider.

A. In today's competitive marketplace, the Company is always facing the potential loss of large customers. Should the Company lose one or more of these customers, the effect would be to increase costs for other customers. Utility companies around the country are working with their regulators to find innovative ways to recognize and deal with competitive issues. Northwestern proposes to enhance its ability to retain large customers by means of this rider.

Under this rider, customers with daily requirements of 2,000 therms or more would be offered service agreements with a term of at least five years. During the first year on a five-year contract, customers would receive a discount on the non-gas portion of their commodity rate of eight

percent. The following year the discount would drop to one-half, or four percent, and each year thereafter would decrease the discount by one percentage point. Thus a customer with only one year remaining on his contract term would receive a discount of only one percent. Obviously, there is a significant incentive for customers to maximize the discount by renewing their contract each year for a full five-year term.

It is estimated that perhaps twenty to twenty-five customers representing about one-third of the Company's total sales volume would be eligible for the Extended Service Rider. Having these large customers on five-year contracts significantly reduces the potential for loss due to bypass or alternate fuels and protects both the Company and its smaller customers against the adverse effects of system load losses.

Q. Would you be asking other customers to subsidize these discounts to the large customers?

A. In this case we ask that the rates to other customers be increased to offset discounts offered. We believe that this is justified for a number of reasons. First, of course, is the protection given against the adverse effects that would result from the loss of such large customer loads. Another very important reason is that the smaller customers continue to be subsidized by larger customers as evidenced by the high rates of return that result under the rates proposed for these large customers. Even with the maximum discount offered under the rider, rates of return would continue to be well above the system average.

Q. Have you increased the rates filed with this application to recognize the effects of these discounts?

A. No, we do not know how many of the eligible customers, if any, would be willing to sign the proposed extended service agreement. In today's market, a five-year term is difficult to obtain; indeed that is in itself is an indication of the value of the extended service agreement.

We are asking the Commission to work with us in addressing competitive issues, and are putting this proposal out as a starting point for discussion. We believe that approval would be in the best interests of all customers.

Q. Does this conclude your prepared direct testimony in this proceeding?

A. Yes, it does.

NG99-002

CONFIDENTIAL

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Exhibit D

NORTHWESTERN PUBLIC SERVICE COMPANY
Analysis of Large Customer Bypass Threat
Avoided Cost < $0.50 per MMBtu

Customer Name	Annual MMBtu	Distance in Feet to Nearest Non-NWPS Line	Size Pipe Needed	Estimated Cost of Bypass	Annual Debt Payment for 10 Years @ 6% Interest
South Dakota Soybean Processors	438,000	2,225' - NNG	2" & 3"	$153,776	$22,389
3-M Company - Brookings	309,400	21,120' - NNG	2" & 3"	$306,602	$44,639
Dakota Pork	299,615	1,250' - NNG	2"	$86,375	$12,576
Heartland Grain Fuels	248,153	31,700' - NBPL	3"	$353,024	$51,398
Brein Enterprises	263,406	17,000' - NNG	2" & 3"	$249,380	$36,308
Big Stone Cheese	90,380	2,250' - NNG	3" & 4"	$90,100	$13,118
SDSU Boilers	93,562	9,180' - NNG	2"	$126,818	$18,464
McCain Foods	161,799	21,200' - NNG	2" & 3"	$207,560	$30,219
Lake Norden Creamery	248,092	73,920' - NNG	2" & 3"	$537,992	$78,328
SD Development Center	66,418	6,000' - NNG	2" & 3"	$103,500	$15,069
Land-O-Lakes Cheese	66,805	2,250' - NNG	2"	$91,475	$13,318
Iowa Pork Packers	62,028	7,000' - NNG	2" & 3"	$107,000	$15,578

Exhibit E

NORTHWESTERN PUBLIC SERVICE
GAS PLANT CLEAN -UP SERVICES BY VENDOR

AMOUNT	*PERCENTAGE*	*CUMULATIVE %*	*SERVICES PROVIDED*
$3,189,775	65.33%	65.33%	*Dustcoating*. Thermal absorption, some heavy equipment extras
$901,902	18.47%	83.81%	*Barr Engineering*. Soil, Air, Water Testing, 24 hour on site, engineering fees
$215,914	4.42%	88.23%	*Natural Gas*. Fuel for thermal absorption unit.
$211,803	4.34%	92.57%	*Groves Construction* Sidewalks, pits, black dirt, etc. Various labor/material, "Lay Sub Grade", Stabilize renovation site, purchase, install, and remove bunkers
$104,000	2.13%	94.70%	*EPRI* Investigation and reporting
$93,625	1.92%	96.82%	*Mandrel Construction* Compact, remove rubble, back fill and compact north 1/2 of project under Phase II, red granite rock
$44,734	0.92%	97.53%	*Jones, Day, Reavi* Attorney fee, insurance recovery matters
$43,168	0.88%	98.42%	*Miscellaneous Under $5,000* J. D. Concrete move holding bunkers; Pierce & Harris, engineering; Roth Plumbing - man holes , meter pits, and catch basins; Marvin Appliance, wood for west area; Dustcoating, remove fence.
$24,405	0.50%	98.92%	*Meyers Sand & Gravel* Move soil to G.T.P. and West Park Sub area and level to grade, level grade west area.
$12,638	0.26%	99.18%	*Huron Drilling* Plug and cap 5 water wells on side Labor and material
$12,000	0.25%	99.42%	*East River Nursery* Prepare and seed west area and plant trees (same area), accordance SDDNR
$11,698	0.24%	99.66%	*Olson Construction* Install first security chain link fence around site, Market to Montana, Center to Market, Haul gas compressor to Mitchell form Huron peaking plant, sewer/water work, plug lines from site.
$9,461	0.19%	99.85%	*Anderson Excavating* Extra non-bid work with heavy equipment, site safety personnel required by OSHA (Dakota Env. Co.), remove asbestos from house and gas compressors old gas plant, gas piping removal.
$7,113	0.15%	100.00%	*Michaels Fence* Chain link fence and labor to install, west area.
Total $4,882,216			

Soil 'roasting' eliminates coal tar

Site preparation earns EPA honors

BY ROGER LARSEN
OF THE PLAINSMAN

When Northwestern Public Service Company officials began their preliminary talks about consolidating operations, an appropriate site was near the top of the list.

They didn't have to look far.

It simply made too much sense to not build on property it already owned at Market Street and Montana Avenue Southwest.

Still, there was a major obstacle to overcome. Coal tar, the byproduct of a one-time manufactured gas plant that mixed coal and fuel oil for use in Huron homes, had to be removed from the soil.

It was a formidable task.

"I think it was decided initially that Merle (Lewis, president and chief executive officer) knew we had the site and elected to move forward and get it cleaned up," said Art Donnell, vice president of energy operations and the management's point man on the project.

"We decided to be aggressively pro-active in this environmental cleanup, rather than reactive," he said.

Ed Highland, then the company's chief engineer, was brought in from the Yankton division to oversee the cleanup.

Highland continues to work for NWPS in Huron today, now as director of safety and environment.

In April 1995, Minnesota-based Dustcoating Inc., a company that pioneered soil remediation technology, was hired. Workers set up huge rotary kilns to convert about 45,000 tons of soil contaminated with coal tar into clean dirt. The process heated the soil to about 1,300 degrees.

Once cleaned, it was buried on the site, compacted and covered with six inches of dirt.

"There's nothing wrong with the soil we put back into the ground," Highland said.

The five-month effort, completed about Labor Day a year ago, caught the attention of the Environmental Protection Agency's Region 8 office, which encompasses most states in the western part of the country.

Earlier this year, NWPS was notified it had won some coveted EPA recognition.

"We were basically the only privately owned utility in Region 8 that received that award," Highland said.

Longtime Huron residents remember the corner of Market Street and Montana Avenue Southwest, which has had an NWPS presence for much of its corporate history in the community.

In the 1920s and '30s, the company produced energy to heat Huron homes and keep gas lights flaming by combining coal and fuel oil. The byproduct was coal tar, which contaminated the dirt long after the 1940s, when the process ended in favor of natural gas and propane.

"When we went in there and did our preliminary investigation, there was some (coal tar) in the soil and in order to put the building there — and make sure no one was at risk — we decided to clean up the whole area, rather than just take a portion of it," Highland said last fall.

"It's cheaper to do it all than to come back in another 10 years," he said.

The process was monitored from the start. As part of state rules, none of the soil could leave the site because, although roasted, it's still considered a hazardous substance. Officials declined to reveal project costs.

Samples of cleaned soil were checked after every 200 tons. An estimated 788,000 gallons of water were treated on the site.

Today, the acreage surrounding the NWPS operations center is landscaped with sod, trees, bushes and flowers.

Property west of the building has been restored and hydroseeded for use as parking for the State Fair.

Across the street to the north, NWPS' new substation is also completed, surrounded by decorative walls that meet the rules as far as height and markings. The area between the street and the walls has also been landscaped.

"We've designed it to be within code and still look like a real community project," Highland said.

From his second-floor office, he has an unobstructed view of the grounds that have so much Huron history. He thinks the neighborhood will prosper in years to come.

"I think this area is going to grow," he said. "You look out here today, and it's really something."

A look back

Power company has storied history in S.D. Heartland

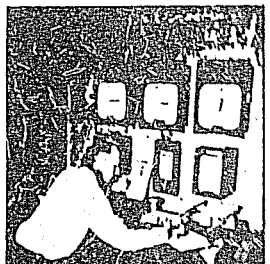
BY CRYSTAL PUGSLEY
staff writer

Fueled by coal, wood chips and even horse manure, the earliest electric power generators in Huron toiled long and hard to provide a few precious hours of illumination.

E.T. Bowe, a son of pioneer settlers who came to Huron in the 1880s, operated one of the first utility generators near the Third Street bridge over the James River. Two other individuals had worked to provide power before him.

Bowe used two 60 horsepower boilers to create electricity for the 1,200 candle street lights that were on in Huron from dusk to midnight.

The lights could be kept burning longer on nights when dances were in town, shedding a luminous glow similar to strong moonlight to help revelers return home.



Dispatch center, 1949.

In the 1890s, Bowe upgraded his system so he could provide electricity for incandescent lighting service to residents and businesses in town.

And he wasn't going to let the simple fact that wiring was nonexistent stop him.

In order to gain customers, Bowe offered to do residential house wiring, which usually consisted of bare wires running exposed along inside walls. Still, a bare light bulb hanging from a drop cord was the height of modernity for a homeowner near the turn of the century.

Boiler fuel for small-town electric light systems was anything from the abundant lignite coal to wood shavings. For Bowe's plant, a man was paid $50 a month to collect horse manure and straw from the city's numerous livery stables.

Huron residents frequently commented when the intensity of the lights brightened rapidly that Bowe must have thrown another forkful on the fire.

While the 1890s was a time of wild growth for electric consumption, they were rocky years for entrepreneurs in small towns who tried to provide the service. Building an electric utility system was a costly proposition, requiring outlays for boilers, generators, distribution lines and home wiring.

The Huron Light and Power Company — one of the major predecessors of Northwestern Public Service Company — was incorporated on May 25, 1907, by Coler Campbell.

The company purchased Bowe's property near the river and made immediate plans to upgrade the facility to improve electric service to the town.

Huron Light and Power's first president was J.W. Campbell, the founder of Huron's First National Bank and builder of one of the city's most prestigious homes.

In 1908, it built a manufactured gas plant — in about the same area as the new NWPS office is today — and in 1910, it added 300 kilowatts of electric generating equipment.

Prior to the 1920s, few records were kept for small utility companies. But a record does exist from a Nov. 7, 1910, audit of the Huron Light and Power Company. Performing the audit was the H.M. Byllesby Co., one of the giants of the electric power industry in the United States.

H.M. Byllesby's dream was to build a utility holding company, and in all, he purchased 25 utility properties and consolidated them into the Northern States Power Company of Minneapolis.

His auditors were in Huron in the fall of 1910 to examine the property for possible inclusion in the expanding NSPC system.

Huron's population in 1910 was about 5,200, and a construction boom was evidenced in 25 new houses being built. The town then had five hotels. The audit points to a $100,000 post office that had been ordered.

"The day we left Huron, ground was purchased for the erection of a large sized Opera House and block of stores with offices above," the audit reads. "The city has probably built 125 houses during the past two years."

At that time, Huron Light and Power Company had a franchise issued by the city in 1909 to furnish the city arc lamps of 1,200 candle power from dark to midnight.

In 1910, the utility was serving 407 gas cooking ranges, and about 110 of the company's electric customers had purchased electric fa... to help cope with the hot and humid summers. Eight customers owned electric washing machines.

For whatever reasons, the talks between Campbell of Huron Light and Power Company and the Byllesby interests broke down and the local firm remained independent for the next 13 years.

On Nov. 27, 1923, Northwestern Public Service Company was incorporated at a law office in Wilmington, Dela., connecting two utility properties in Nebraska and two in South Dakota.

The utility business was becoming more difficult for small-time operators to handle with only a handful of staff members.

Most of the manpower concentrated in the field, at the power plants and on the line crews. The primary job of the general office staff was to get bills posted and mailed to customers each month.

Within a year of incorporating, NWPS was the majority investor in the Huron Light and Power Company. The Campbell family lost control of the utility, and by early 1924, the company was run by J.A. Ward.

At its regular quarterly meeting in New York on April 29, 1924, the NWPS board of directors appointed Ward as vice president of the company.

Three weeks later, at a special meeting, the board authorized the purchase of Huron Light and Power.

Many believe the 18-day gap between the election of Ward as vice president and NWPS's purchase of Huron Light and Power was used to make a deal with Huron city officials to house the headquarters of the new company. Aberdeen was also in the running for headquartering the

HISTORY/page 12

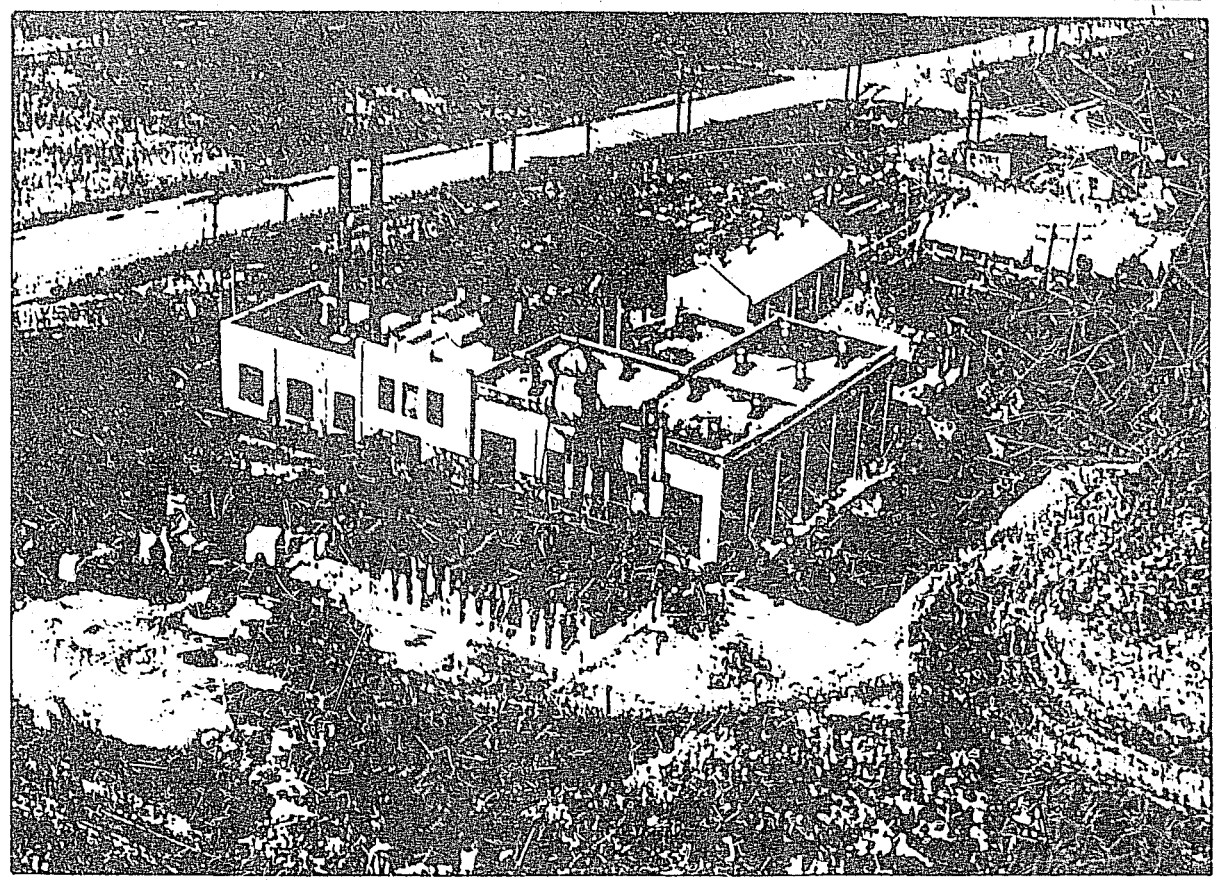


PHOTO COURTESY OF NWPS

This NWPS substation and power plant building are pictured in the early 1940s on the Market Road site where the new operations center stands today.

Additional exhibits with supporting details for tariff changes

Distribution Lost & Unaccounted For - Fuel Retention %

Northwestern filed for a 3.04% Fuel Retention for transportation. PAM took exception to this percentage, saying it was too high. Attached as Exhibit A are the last 2 years of actual activity on NWPS' gas system in South Dakota (12 months ending 7/31). The lost & unaccounted for percentage is 3.06% and 5.25% in 1996 and 1995, respectively. Northwestern is proposing using the actual data to develop annual fuel retention percentages.

Manufactured Gas Plant Removal Cost Surcharge

Attached as Exhibit B is a new surcharge calculation using a standard $0.14/MMBtu surcharge rate for all rate schedules and customer classes. Northwestern is proposing this alternative in settlement, with a pragmatic adjustment to realign rates for all rate schedules.

Reconciliation of Proposed Rates

Attached as Exhibit C is a reconciliation of new proposed rates. The key feature is the development of two rate options for large C&I customers. This was proposed to meet PAM's concern that customers within a range of usage should pay similar customer charges. Two levels of customer charges are proposed, $70 and $260 per month. The non-gas commodity rate, including the gas plant cleanup surcharge, is $0.55/MMBtu associated with the $70 customer charge and $0.35/MMBtu associated with the $260 customer charge.

Index Pricing for Large Sales Customers

Northwestern proposes that large sales rate schedules include a market index price for the gas commodity equal to an average of the first of month NNG Ventura and Demarcation indices as shown in Inside F.E.R.C. Market Report. Attached as Exhibit D is a comparison of this benchmark price against actual gas commodity costs for the first 8 months of 1996. As shown on the workpaper, actual costs are $0.025/MMBtu below the benchmark. PAM wanted us to show the Commission support for our pricing of gas to larger users.

Run By : GODOUGH
Page No.: 1

NORTHWESTERN PUBLIC SERVICE COMPANY
GAS PURCHASED COSTS
FOR PERIOD ENDING 7/31/1996

Run Date: 8/17/1996
Run Time: 16:07:21
Report : GASPURCTSD

SOUTH DAKOTA	CURRENT MONTH THIS YEAR	CURRENT MONTH BUDGET	CURRENT MONTH LAST YEAR	YEAR TO DATE THIS YEAR	YEAR TO DATE BUDGET	YEAR TO DATE LAST YEAR	12 MONTHS THIS YEAR
Gas Purchased Costs							
Demand-SF, SSF Res	0	539,908	0	0	4,413,721	0	0
Demand-SMS Res	5,250	5,250	10,500	36,750	36,750	73,500	89,250
Demand-Firm Throughput	482,393	0	531,306	4,071,324	0	4,242,929	6,991,557
Demand-Firm Defer Delivery	34,702	39,935	34,702	120,433	138,595	120,433	244,950
Commodity-SF	(24,201)	452,226	(128,033)	(61,080)	8,597,206	(221,173)	(334,108)
Commodity-AOS,ACDS,ERS	0	0	0	0	0	0	0
Commodity-Firm Throughput	355,646	0	389,013	8,487,126	0	6,478,690	14,281,530
Commodity-Irpt Throughput	160,920	0	324,823	2,168,706	0	3,855,171	3,540,657
Total Purchased Gas	1,015,210	1,037,319	1,162,311	14,823,259	13,186,272	14,549,550	24,813,836
Deferred Gas Cost Adjustment	(77,087)	(3,909)	38,693	943,432	1,617,065	1,432,603	(271,936)
Total Purchased Gas Sold	938,123	1,033,410	1,201,004	15,766,691	14,803,337	15,982,153	24,541,900
MMBTU Purchased							
Demand-SF,SSF Res	0	0	0				
Demand-SMS Res	3,000	0	6,000				
Demand-Firm Throughput	32,289	0	32,289				
Demand-Firm Defer Delivery	6,938	0	6,938				
Commodity-SF	(11,999)	266,823	(78,068)	(29,444)	4,848,247	(114,978)	(193,833)
Commodity-WPS,ACDS,SS,ERS	0	0	0	0	0	0	0
Commodity-Firm Throughput	193,934	0	218,516	4,176,237	0	3,222,466	7,342,048
Commodity-Irpt Throughput	89,904	0	148,325	1,424,249	0	1,995,238	1,979,013
Commodity-ISS	0	0	0	0	0	0	0
Total MMBTU Purchased	271,839	266,823	288,773	5,571,042	4,848,247	5,102,726	9,127,228
Total MMBTU Transport	1,897	0	0	79,914	0	0	100,507
Total Gas Received	273,736	266,823	288,773	5,650,956	4,848,247	5,102,726	9,227,735
Dollars Per Unit Purchased	3.73	3.89	4.02	2.66	2.72	2.85	2.72
Gas Statistics							
Total MMBTU Made	0	0	0	39,688	0	4,231	42,935
Total MMBTU Sendout	271,839	266,823	288,773	5,610,730	4,848,247	5,106,957	9,170,163
MMBTU Sold	272,815	254,736	279,395	5,903,681	5,381,347	5,549,555	8,762,360
MMBTU Company Use	84	0	160	22,535	0	9,459	26,971
MMBTU Transported Only	1,897	0	0	79,914	0	0	100,507
Total Gas Accounted For	274,796	254,736	279,555	6,006,330	5,381,347	5,559,014	8,889,838
MMBTU Unaccounted For	(2,957)	12,087	9,218	(395,600)	(533,100)	(452,057)	280,525

3.06%

08/15/95

NORTHWESTERN PUBLIC SERVICE COMPANY
GAS PURCHASED COSTS
FOR PERIOD ENDING
07/31/95

— SOUTH DAKOTA —	CURRENT MONTH THIS YEAR	CURRENT MONTH BUDGET	CURRENT MONTH LAST YEAR	YEAR TO DATE THIS YEAR	YEAR TO DATE BUDGET	YEAR TO DATE LAST YEAR	12 MONTHS THIS YEAR
-------- PURCHASED GAS --------							
GAS PURCHASED COSTS							
DEMAND-SF,SSF RES		548,395			4,473,892		
DEMAND-SNS RES	10,500		10,500	73,500		73,500	126,000
DEMAND-FIRM THROUGHPUT	531,306		534,331	4,242,929		4,578,264	7,336,974
DEMAND-FIRM DEFER DELIVERY	34,702		34,702	120,433		120,433	244,950
COMMODITY-SF	(128,033)	456,579	84,870	(221,173)	9,697,964	574,768	(62,202)
COMMODITY-AQS,ACDS,ERS							
COMMODITY-FIRM THROUGHPUT	389,013		38,602	6,478,690		6,409,789	10,220,652
COMMODITY-INTRPT THROUGHPUT	324,823		174,888	3,855,171		3,568,721	6,530,198
TOTAL PURCHASED GAS	1,162,311 -5	1,004,974	877,893	14,549,550	14,171,856	15,325,475	24,396,572
DEFERRED GAS COST ADJUSTMENT	38,693	(6,950)	221,948	1,432,603	1,802,638	1,524,510	25,421
TOTAL PURCHASED GAS SOLD	1,201,004	998,024	1,099,841	15,982,153	15,774,494	16,849,985	24,421,993
MMBTU PURCHASED							
DEMAND,SF,SSF RES							
DEMAND-SNS RES	6,000		6,000				
DEMAND-FIRM THROUGHPUT	32,289		32,289				
DEMAND-FIRM DEFER DELIVERY	6,938		6,938				
COMMODITY-SF	(78,068)	234,746	42,023	(114,978)	4,594,124	243,912	(22,709)
COMMODITY-WPS,ACDS,SS,ERS							
COMMODITY-FIRM THROUGHPUT	218,516		14,860	3,222,466		3,007,433	5,019,491
COMMODITY-INTRPT THROUGHPUT	148,325		111,062	1,995,238		1,701,041	3,357,855
COMMODITY-ISS							
TOTAL MMBTU PURCHASED	288,773 -5	234,746	167,945	5,102,726	4,594,124	4,952,386	8,354,637
TOTAL MMBTU TRANSPORT ONLY						67,958	(2,270)
TOTAL GAS RECEIVED	288,773	234,746	167,945	5,102,726	4,594,124	5,020,344	8,352,367
DOLLARS PER UNIT PURCHASED	4.03	4.28	5.23	2.85	3.08	3.09	2.92
GAS STATISTICS							
TOTAL MMBTU MADE				4,231		51,738	4,231
TOTAL MMBTU SENDOUT	288,773	234,746	167,945	5,106,957	4,594,124	5,004,124	8,358,868
DMBTU SOLD	279,395	229,304	236,630	5,549,555	5,207,893	5,465,100	7,909,396
MMBTU COMPANY USE	160		133	9,459		10,523	13,189
DMBTU TRANSPORTED ONLY						67,958	(2,270)
TOTAL GAS ACCOUNTED FOR	279,555	229,304	236,763	5,559,014	5,207,893	5,543,581	7,920,315
MMBTU UNACCOUNTED FOR	9,218	5,442	(68,818)	(452,057)	(613,769)	(539,457)	438,553

5.25%

Exhibit B

NORTHWESTERN PUBLIC SERVICE COMANY

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Summary

Line No.	Month	Year	1/	Beginning of Month Balance	2/ Return & Associated Income Taxes	Cost Additions	Amortization Page 3 of 6	End of Month Balance
	(a)	(b)		(c)	(d)	(e)	(f)	(g)
				$	$	$	$	$
1	November	1994	A	0	0	0	(14,471)	(14,471)
2	December	1994	A	(14,471)	(169)	0	(48,747)	(63,387)
3								
4	January	1995	A	(63,387)	(739)	865,274	(58,705)	742,443
5	February	1995	A	742,443	8,652	18,711	(59,321)	710,485
6	March	1995	A	710,485	8,280	158,626	(49,952)	827,439
7	April	1995	A	827,439	9,643	474,308	(42,631)	1,268,759
8	May	1995	A	1,268,759	14,786	169,435	(29,767)	1,423,213
9	June	1995	A	1,423,213	16,586	1,086,276	(18,918)	2,507,157
10	July	1995	A	2,507,157	29,218	539,945	(13,747)	3,062,573
11	August	1995	A	3,062,573	35,691	817,299	(12,283)	3,903,280
12	September	1995	A	3,903,280	45,488	523,265	(13,465)	4,458,568
13	October	1995	A	4,458,568	51,959	86,014	(19,880)	4,576,661
14	November	1995	A	4,576,661	53,336	12,760	(42,545)	4,600,212
15	December	1995	A	4,600,212	53,610	130,302	(53,478)	4,730,646
16								
17	January	1996	A	4,730,646	55,130	0	(60,178)	4,725,598
18	February	1996	A	4,725,598	55,071	0	(69,109)	4,711,560
19	March	1996	A	4,711,560	54,908	0	(55,629)	4,710,839
20	April	1996	A	4,710,839	54,899	0	(46,193)	4,719,545
21	May	1996	A	4,719,545	55,001	0	(30,455)	4,744,091
22	June	1996	P	4,744,091	55,287	0	(18,918)	4,780,460
23	July	1996	P	4,780,460	55,711	0	(13,747)	4,822,424
24	August	1996	P	4,822,424	56,200	0	(34,949)	4,843,675
25	September	1996	P	4,843,675	56,447	0	(38,317)	4,861,805
26	October	1996	P	4,861,805	56,659	0	(56,568)	4,861,896
27	November	1996	P	4,861,896	56,660	0	(121,063)	4,797,493
28	December	1996	P	4,797,493	55,909	0	(152,172)	4,701,230
29								
30	January	1997	P	4,701,230	54,787	0	(171,237)	4,584,780
31	February	1997	P	4,584,780	53,430	0	(196,652)	4,441,558
32	March	1997	P	4,441,558	51,761	0	(158,294)	4,335,025
33	April	1997	P	4,335,025	50,520	0	(131,445)	4,254,100
34	May	1997	P	4,254,100	49,577	0	(86,662)	4,217,015
35	June	1997	P	4,217,015	49,144	0	(53,832)	4,212,327
36	July	1997	P	4,212,327	49,090	0	(39,115)	4,222,302
37	August	1997	P	4,222,302	49,206	0	(34,949)	4,236,559
38	September	1997	P	4,236,559	49,372	0	(38,317)	4,247,614
39	October	1997	P	4,247,614	49,501	0	(56,568)	4,240,547
40	November	1997	P	4,240,547	49,419	0	(121,063)	4,168,903
41	December	1997	P	4,168,903	48,584	0	(152,172)	4,065,315
42								
43	January	1998	P	4,065,315	47,377	0	(171,237)	3,941,455
44	February	1998	P	3,941,455	45,933	0	(196,652)	3,790,736
45	March	1998	P	3,790,736	44,177	0	(158,294)	3,676,619
46	April	1998	P	3,676,619	42,847	0	(131,445)	3,588,021
47	May	1998	P	3,588,021	41,814	0	(86,662)	3,543,173
48	June	1998	P	3,543,173	41,292	0	(53,832)	3,530,633
49	July	1998	P	3,530,633	41,145	0	(39,115)	3,532,663
50	August	1998	P	3,532,663	41,169	0	(34,949)	3,538,883
51	September	1998	P	3,538,883	41,242	0	(38,317)	3,541,808
52	October	1998	P	3,541,808	41,276	0	(56,568)	3,526,516
53	November	1998	P	3,526,516	41,097	0	(121,063)	3,446,550
54	December	1998	P	3,446,550	40,166	0	(152,172)	3,334,544
55								

56 1/ A=Actual, P=Projected

57 2/ Return @ 9.09% and Income Taxes @ 35% Allowed in Docket No. NG94-008

NORTHWESTERN PUBLIC SERVICE COMANY

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Summary

Line No.	Month	Year		Beginning of Month Balance	2/ Return & Associated Income Taxes	Cost Additions	Amortization Page 4 of 6	End of Month Balance
	(a)	(b)	1/	(c) $	(d) $	(e) $	(f) $	(g) $
1	January	1999	P	3,334,544	38,860	0	(171,237)	3,202,167
2	February	1999	P	3,202,167	37,318	0	(196,652)	3,042,833
3	March	1999	P	3,042,833	35,461	0	(158,294)	2,920,000
4	April	1999	P	2,920,000	34,029	0	(131,445)	2,822,584
5	May	1999	P	2,822,584	32,894	0	(86,662)	2,768,816
6	June	1999	P	2,768,816	32,267	0	(53,832)	2,747,251
7	July	1999	P	2,747,251	32,016	0	(39,115)	2,740,152
8	August	1999	P	2,740,152	31,933	0	(34,949)	2,737,136
9	September	1999	P	2,737,136	31,898	0	(38,317)	2,730,717
10	October	1999	P	2,730,717	31,823	0	(56,568)	2,705,972
11	November	1999	P	2,705,972	31,535	0	(121,063)	2,616,444
12	December	1999	P	2,616,444	30,492	0	(152,172)	2,494,764
13								
14	January	2000	P	2,494,764	29,074	0	(171,237)	2,352,601
15	February	2000	P	2,352,601	27,417	0	(196,652)	2,183,366
16	March	2000	P	2,183,366	25,445	0	(158,294)	2,050,517
17	April	2000	P	2,050,517	23,896	0	(131,445)	1,942,968
18	May	2000	P	1,942,968	22,643	0	(86,662)	1,878,949
19	June	2000	P	1,878,949	21,897	0	(53,832)	1,847,014
20	July	2000	P	1,847,014	21,525	0	(39,115)	1,829,424
21	August	2000	P	1,829,424	21,320	0	(34,949)	1,815,795
22	September	2000	P	1,815,795	21,161	0	(38,317)	1,798,639
23	October	2000	P	1,798,639	20,961	0	(56,568)	1,763,032
24	November	2000	P	1,763,032	20,546	0	(121,063)	1,662,515
25	December	2000	P	1,662,515	19,375	0	(152,172)	1,529,718
26								
27	January	2001	P	1,529,718	17,827	0	(171,237)	1,376,308
28	February	2001	P	1,376,308	16,039	0	(196,652)	1,195,695
29	March	2001	P	1,195,695	13,934	0	(158,294)	1,051,335
30	April	2001	P	1,051,335	12,252	0	(131,445)	932,142
31	May	2001	P	932,142	10,863	0	(86,662)	856,343
32	June	2001	P	856,343	9,980	0	(53,832)	812,491
33	July	2001	P	812,491	9,469	0	(39,115)	782,845
34	August	2001	P	782,845	9,123	0	(34,949)	757,019
35	September	2001	P	757,019	8,822	0	(38,317)	727,524
36	October	2001	P	727,524	8,478	0	(56,568)	679,434
37	November	2001	P	679,434	7,918	0	(121,063)	566,289
38	December	2001	P	566,289	6,599	0	(152,172)	420,716
39								
40	January	2002	P	420,716	4,903	0	(171,237)	254,382
41	February	2002	P	254,382	2,965	0	(196,652)	60,695
42	March	2002	P	60,695	707	0	(61,402)	0
43								

44 1/ A=Actual, P=Projected
45 2/ Return @ 9.09% and Income Taxes @ 35% Allowed in Docket No. NG94-008

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Amortization

				Rate Nos. 81 & 82 Recovery			All Other Rate Nos. Recovery		
Line No.	Month	Year		Therms	Amortization Rate	Costs Recovered in Rates	Therms	Amortization Rate	Costs Recovered in Rates
	(a)	(b)		(c)	(d) $/Therm	(e) $	(f)	(g) $/Therm	(h) $
			1/						
1	November	1994	A	1,893,750	$0.00492	9,317	1,047,640	$0.00492	5,154
2	December	1994	A	6,427,410	$0.00492	31,623	3,480,460	$0.00492	17,124
3									
4	January	1995	A	8,424,760	$0.00492	41,450	3,507,080	$0.00492	17,255
5	February	1995	A	8,436,750	$0.00492	41,509	3,620,280	$0.00492	17,812
6	March	1995	A	7,015,650	$0.00492	34,517	3,137,100	$0.00492	15,435
7	April	1995	A	5,586,340	$0.00492	27,485	3,078,470	$0.00492	15,146
8	May	1995	A	3,528,160	$0.00492	17,359	2,521,850	$0.00492	12,408
9	June	1995	A	1,716,080	$0.00492	8,443	2,129,080	$0.00492	10,475
10	July	1995	A	922,670	$0.00492	4,540	1,871,280	$0.00492	9,207
11	August	1995	A	746,670	$0.00492	3,674	1,749,740	$0.00492	8,609
12	September	1995	A	903,340	$0.00492	4,444	1,833,600	$0.00492	9,021
13	October	1995	A	1,712,160	$0.00492	8,424	2,328,450	$0.00492	11,456
14	November	1995	A	4,942,040	$0.00492	24,315	3,705,270	$0.00492	18,230
15	December	1995	A	7,269,890	$0.00492	35,768	3,599,560	$0.00492	17,710
16									
17	January	1996	A	8,719,660	$0.00492	42,901	3,511,580	$0.00492	17,277
18	February	1996	A	10,342,880	$0.00492	50,887	3,703,720	$0.00492	18,222
19	March	1996	A	7,816,680	$0.00492	38,458	3,490,000	$0.00492	17,171
20	April	1996	A	6,129,090	$0.00492	30,155	3,259,850	$0.00492	16,038
21	May	1996	A	3,586,760	$0.00492	17,647	2,603,340	$0.00492	12,808
22	June	1996	P	1,716,080	$0.00492	8,443	2,129,080	$0.00492	10,475
23	July	1996	P	922,670	$0.00492	4,540	1,871,280	$0.00492	9,207
24	August	1996	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
25	September	1996	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
26	October	1996	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
27	November	1996	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
28	December	1996	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
29									
30	January	1997	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
31	February	1997	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
32	March	1997	P	7,816,680	$0.01400	109,434	3,490,000	$0.01400	48,860
33	April	1997	P	6,129,090	$0.01400	85,807	3,259,850	$0.01400	45,638
34	May	1997	P	3,586,760	$0.01400	50,215	2,603,340	$0.01400	36,447
35	June	1997	P	1,716,080	$0.01400	24,025	2,129,080	$0.01400	29,807
36	July	1997	P	922,670	$0.01400	12,917	1,871,280	$0.01400	26,198
37	August	1997	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
38	September	1997	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
39	October	1997	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
40	November	1997	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
41	December	1997	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
42									
43	January	1998	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
44	February	1998	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
45	March	1998	P	7,816,680	$0.01400	109,434	3,490,000	$0.01400	48,860
46	April	1998	P	6,129,090	$0.01400	85,807	3,259,850	$0.01400	45,638
47	May	1998	P	3,586,760	$0.01400	50,215	2,603,340	$0.01400	36,447
48	June	1998	P	1,716,080	$0.01400	24,025	2,129,080	$0.01400	29,807
49	July	1998	P	922,670	$0.01400	12,917	1,871,280	$0.01400	26,198
50	August	1998	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
51	September	1998	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
52	October	1998	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
53	November	1998	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
54	December	1998	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
55									
56	1/ A=Actual, P=Projected								

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Amortization

Line No.	Month	Year		Rate Nos. 81 & 82 Recovery			All Other Rate Nos. Recovery		
				Therms	Amortization Rate	Costs Recovered in Rates	Therms	Amortization Rate	Costs Recovered in Rates
	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)
			1/		$/Therm	$		$/Therm	$
1	January	1999	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
2	February	1999	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
3	March	1999	P	7,816,680	$0.01400	109,434	3,490,000	$0.01400	48,860
4	April	1999	P	6,129,090	$0.01400	85,807	3,259,850	$0.01400	45,638
5	May	1999	P	3,586,760	$0.01400	50,215	2,603,340	$0.01400	36,447
6	June	1999	P	1,716,080	$0.01400	24,025	2,129,080	$0.01400	29,807
7	July	1999	P	922,670	$0.01400	12,917	1,871,280	$0.01400	26,198
8	August	1999	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
9	September	1999	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
10	October	1999	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
11	November	1999	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
12	December	1999	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
13									
14	January	2000	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
15	February	2000	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
16	March	2000	P	7,816,680	$0.01400	109,434	3,490,000	$0.01400	48,860
17	April	2000	P	6,129,090	$0.01400	85,807	3,259,850	$0.01400	45,638
18	May	2000	P	3,586,760	$0.01400	50,215	2,603,340	$0.01400	36,447
19	June	2000	P	1,716,080	$0.01400	24,025	2,129,080	$0.01400	29,80.
20	July	2000	P	922,670	$0.01400	12,917	1,871,280	$0.01400	26,198
21	August	2000	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
22	September	2000	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
23	October	2000	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
24	November	2000	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
25	December	2000	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
26									
27	January	2001	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
28	February	2001	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
29	March	2001	P	7,816,680	$0.01400	109,434	3,490,000	$0.01400	48,860
30	April	2001	P	6,129,090	$0.01400	85,807	3,259,850	$0.01400	45,638
31	May	2001	P	3,586,760	$0.01400	50,215	2,603,340	$0.01400	36,447
32	June	2001	P	1,716,080	$0.01400	24,025	2,129,080	$0.01400	29,807
33	July	2001	P	922,670	$0.01400	12,917	1,871,280	$0.01400	26,198
34	August	2001	P	746,670	$0.01400	10,453	1,749,740	$0.01400	24,496
35	September	2001	P	903,340	$0.01400	12,647	1,833,600	$0.01400	25,670
36	October	2001	P	1,712,160	$0.01400	23,970	2,328,450	$0.01400	32,598
37	November	2001	P	4,942,040	$0.01400	69,189	3,705,270	$0.01400	51,874
38	December	2001	P	7,269,890	$0.01400	101,778	3,599,560	$0.01400	50,394
39									
40	January	2002	P	8,719,660	$0.01400	122,075	3,511,580	$0.01400	49,162
41	February	2002	P	10,342,880	$0.01400	144,800	3,703,720	$0.01400	51,852
42	March	2002	P	7,816,680	$0.00543	42,449	3,490,000	$0.00543	18,953
43									
44	1/ A=Actual, P=Projected								

NORTHWESTERN PUBLIC SERVICE COMANY

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Determination of Manufactured Gas Plant Removal Cost Adjustment Portion of Rates

Line No.	Rate No. and Class of Customer (a)	Docket No. NG94-008 Non-Gas Cost (b) $	NG94-008 Allowed Gas Plant Removal Cost (c) $	Annual Commodity Therms (d)	NG94-008 Adjustment Clause Component of Rates (e) $/Therm
1			Allocated on		
2		Page 6 of 6	Therms	Page 6 of 6	
3					
4	*Docket No. NG94-008 Component of Rates*				
5					
6	Rate Nos. 81/82 Residential/Small Commercial	8,736,269	245,783	49,906,707	0.00492
7					
8	All Other Rate Nos.	1,410,382	126,145	25,614,030	0.00492
9					
10					
11	Totals	10,146,651	371,928	75,520,737	
12					
13					
14					
15					
16					

	Rate No. and Class of Customer (a)	NG94-008 Adjustment Clause Component of Rates (b) $/Therm	Factor (c)	Future Adjustment Clause Component of Rates (d) $/Therm	Rate Adjustment (e) $/Therm
17					
18					
19					
20					
21					
22					
23					
24	*Future Component of Rates*				
25					
26	Rate Nos. 81/82 Residential/Small Commercial	0.00492	2.85	0.01400	0.00908
27					
28	All Other Rate Nos.	0.00492	2.85	0.01400	0.00908

NORTHWESTERN PUBLIC SERVICE COMANY

Manufactured Gas Plant Removal Cost Adjustment
Reconciliation Report-Docket No. NG94-008 Rate Case Revenues, Gas Costs, Margins and Therm Billing Determinants

Line No.	Rate No. and Class of Customer (a)	Annual Commodity Therms (b)	Annual Demand Therms (c)	Commodity Gas Cost Base Rate (d) $/Therm	Demand Gas Cost Base Rate (e) $/Therm
1	Rate Nos. 81/82 Residential/Small Commercial	49,906,707	0	0.38929	0.00000
2					
3	Rate No. 84 Firm Lg. Commercial/Industrial	5,175,746	407,114	0.24715	1.36366
4					
5	Rate No. 85 Int. Lg. Commercial/Industrial	4,628,635	0	0.25715	0.00000
6					
7	Rate No. 88 Agency Firm	8,166,107	68,048	Varies	1.36366
8					
9	Rate No. 89 Agency Interruptible	4,746,016	0	Varies	0.00000
10					
11					
12	Total Before 3M	72,623,211			
13					
14	3M Flex Transportation	2,897,526			
15					
16					
17	Total Throughput	75,520,737			
18					
19					
20					
21					
22					
23	Rate No. and Class of Customer (a)	Docket No. NG94-008 Base Revenue (b) $	Commodity Gas Cost (c) $	Demand Gas Cost (d) $	Docket No. NG94-008 Non-Gas Cost Recovery (e) $
24					
25					
26					
27	Rate Nos. 81/82 Residential/Small Commercial	28,164,451	19,428,182	0	8,736,269
28					
29	Rate No. 84 Firm Lg. Commercial/Industrial	2,298,253	1,279,186	555,165	463,902
30					
31	Rate No. 85 Int. Lg. Commercial/Industrial	1,498,741	1,190,253	0	308,488
32					
33	Rate No. 88 Agency Firm	2,156,309	1,744,250	92,794	319,265
34					
35	Rate No. 89 Agency Interruptible	2,017,562	1,698,835	0	318,727
36					
37					
38	Totals	36,135,316	25,340,706	647,959	10,146,651

Exhibit C

NORTHWESTERN PUBLIC SERVICE COMPANY

Reconciliation of Rate Changes and Effects on Revenues
Changes in Rates Since Base Rates Established

Line No	Description (a)	Docket No NG94-008 Base Rates (b) $/Therm	PGA Changes thru 6/30/98 (c) $/Therm	Current Rates (d) $/Therm	Remove Non-Gas Portion of Rate No 84 & 86 Demand (e) $/Therm	Remove Rate No 85 Rate Block Differential (f) $/Therm	Adjust Manufactured Gas Plant Removal Cost Tracker (g) $/Therm	Eliminate Rate No 89 (h) $/Therm	Realign Large vs Small Customer (i) $/Therm	Market Rates for Rate No 84 & 85 - Gas Costs (j) $/Therm	Proposed Rates (k) $/Therm
1	RATE NO 81 - Residential Gas Service				Note 1	Note 2	Note 3	Note 4			
2											
3	Customer Charge	$4 50000		$4 50000							$4 50000
4	Commodity Charge										
5	First 30 therms, per therm non-gas portion	$0 21071		$0 21071	$0 00314		$0 00908		$0 00226		$0 22519
6	First 30 therms, per therm gas portion	$0 38929	($0 06258)	$0 32671						$0 00770	$0 33441
7	Over 30 therms, per therm non-gas portion	$0 13271		$0 13271	$0 00314		$0 00908		$0 00226		$0 14719
8	Over 30 therms, per therm gas portion	$0 38929	($0 06258)	$0 32671						$0 00770	$0 33441
9											
10											
11											
12	RATE NO 82 - General Gas Service										
13											
14	Customer Charge	$4 50000		$4 50000							$4 50000
15	Commodity Charge										
16	First 400 therms, per therm non-gas portion	$0 12071		$0 12071	$0 00314		$0 00908		$0 00226		$0 13519
17	First 400 therms, per therm gas portion	$0 38929	($0 06258)	$0 32671						$0 00770	$0 33441
18	Next 1,600 therms, per therm non-gas portion	$0 09071		$0 09071	$0 00314		$0 00908		$0 00226		$0 10519
19	Next 1,600 therms, per therm gas portion	$0 38929	($0 06258)	$0 32671						$0 00770	$0 33441
20	Over 2,000 therms, per therm non-gas portion	$0 06071		$0 06071	$0 00314		$0 00908		$0 00226		$0 07519
21	Over 2,000 therms, per therm gas portion	$0 38929	($0 06258)	$0 32671						$0 00770	$0 33441
22											
23	RATE NO 84 - Commercial and Industrial-Firm										
24											
25	Customer Charge	$70 00000		$70 00000							$70 00000
26	Demand Charge										
27	Per therm of daily contract demand										
28	Non-gas portion	$0 46834		$0 46834	($0 46834)						$0 00000
29	Gas portion	$1 36356	($0 52746)	$0 83620						$0 00360	$0 84000
30	Commodity Charge										
31	All use, per therm non-gas portion	$0 03355		$0 03355	$0 00314	$0 00283	$0 00908		$0 00640		$0 05500
32	All use, per therm gas portion	$0 24715	($0 04164)	$0 20551						$0 01109	$0 21660
33	Released Capacity and Balancing Services Surcharge	$0 00000		$0 00000						$0 01300	$0 01300
34											
35	Note 1				Note 2						
36	Rate No 84 non-gas portion of demand revenues	P 3, C b, L 30	$197,936		Rate No 85 non-gas portion of first rate block		P 2, C b, L 5	$0 05185			
37	Rate No 86 non-gas portion of demand revenues	P 4, C b, L 17	$29,692		Rate No 85 non-gas portion of second rate block		P 2, C b, L 7	$0 03355			
38											
39	Total		$227,628		Differential			$0 01830			
40	Divide by all commodity billing determinants,				Times Rate No 85 first rate block therms		P 4, C k, L 5	3,513,485			
41	exclusive of 3M Brookings (special contract)	P 5, C b, L 12	72,023,211								
42					Revenue shortfall			$64,297			
43	= Commodity rate adjustment (all classes per therm)		$0 00314		Divide by all non Rate No 81 & 82 commodity		P 5, C b, L 3,				
44					billing therms, exclusive of 3M Brookings		5, 7, & 9	22,716,504			
45	Note 3										
46	See Manufactured Gas Plant Removal Cost Adjustment- Reconciliation Report				= Commodity rate adjustment (all non Rate No 81						
47					and 82 classes, per therm)			$0 00283			
48	Note 4										
49	Rate No 89 is rolled into Rate No 88 (One service)										

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NORTHWESTERN PUBLIC SERVICE COMPANY

Reconciliation of Rate Changes and Effects on Revenues
Changes in Rates Since Base Rates Established

Line No	Description	Docket No. NG94-008 Base Rates	PGA Changes thru 6/30/96	Current Rates	Remove Non-Gas Portion of Rate No. 84 & 88 Demand	Remove Rate No. 85 Rate Block Differential	Adjust Manufactured Gas Plant Removal Cost Tracker	Eliminate Rate No. 89	Realign Large vs Small Customer	Market Rates for Rate No 84 & 85 - Gas Costs	Proposed Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		$/Therm	$/Therm	$/Therm	$/Therm Note 1	$/Therm Note 2	$/Therm Note 3	$/Therm Note 4	$/Therm	$/Therm	$/Therm
1	RATE NO. 05 - Commercial and Industrial-Interruptible										
2											
3	Customer Charge	$70.00000		$70.00000							$70.00000
4	Commodity Charge										
5	First 10,000 therms, per therm, non-gas portion	$0.05185		$0.05185	$0.00314	($0.01547)	$0.00908		$0.00640		$0.05500
6	First 10,000 therms, per therm, gas portion	$0.25715	($0.04164)	$0.21551						$0.01409	$0.22960
7	Over 10,000 therms, per therm, non-gas portion	$0.03355		$0.03355	$0.00314	$0.00283	$0.00908		$0.00640		$0.05500
8	Over 10,000 therms, per therm, gas portion	$0.25715	($0.04164)	$0.21551						$0.01409	$0.22960
9											
10											
11											
12	RATE NO. 88 - [Firm] Transportation Service										
13											
14	Customer Charge	$260.00000		$260.00000							$260.00000
15	Commitment Charge										
16	Per therm of daily contract demand										
17	Non-gas portion	$0.43634		$0.43634	($0.43634)						$0.00000
18	Gas portion	$1.38368	($0.52746)	$0.83620						$0.00380	$0.84000
19	Commodity Charge, all therms per month										
20	Delivery Service	$0.03355		$0.03355	$0.00314	$0.00283	$0.00908		($0.01360)		$0.03500
21	Standby Sales Service, per therm										
22	Non-gas portion	$0.03355		$0.03355	$0.00314	$0.00283	$0.00908		($0.01360)		$0.03500
23	Gas portion	$0.24715	($0.04164)	$0.20551						$0.01109	$0.21660
24											
25											
26											
27	RATE NO. 89 - [Interruptible Transportation Service]										
28											
29	Customer Charge	$260.00000		$260.00000				($260.00000)			$0.00000
30	Commodity Charge, all therms per month										
31	Delivery Service	$0.03355		$0.03355	$0.00314	$0.00283	$0.00908	($0.03500)	($0.01360)		($0.00000)

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NORTHWESTERN PUBLIC SERVICE COMPANY

Reconciliation of Rate Changes and Effects on Revenues
Changes in Revenues Since Base Rates Established

Line No	Description	Docket No NG94-008 Base Rates	PGA Changes thru 6/30/96	Current Rates	Remove Non-Gas Portion of Rate No. 84 & 85 Demand	Remove Rate No. 85 Rate Block Differential	Adjust Manufactured Gas Plant Removal Cost Tracker	Eliminate Rate No. 69	Realign Large vs. Small Customer	Market Rates for Rate No. 84 & 85 - Gas Costs	Proposed Rates	Annual Billing Units
	(a)	(b) $	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $	(i) $	(j) $	(k) $	(l)
1	RATE NO. 81 - Residential Gas Service											
2												
3	Customer Charge	1,673,906		1,673,906							1,673,906	371,979
4	Commodity Charge											
5	First 30 therms, per therm: non-gas portion	1,973,669		1,973,669	29,412		85,050		21,169		2,109,300	9,366,755
6	First 30 therms, per therm: gas portion	3,646,384	(566,172)	3,080,212						72,077	3,152,289	9,366,755
7	Over 30 therms, per therm: non-gas portion	3,062,196		3,062,196	72,453		209,515		52,148		3,396,314	23,074,358
8	Over 30 therms, per therm: gas portion	8,992,617	(1,443,993)	7,538,624						177,557	7,716,181	23,074,358
9												
10		19,338,774	(2,030,165)	17,308,609	101,865	0	294,565	0	73,317	249,634	18,027,990	
11												
12	RATE NO. 82 - General Gas Service											
13												
14	Customer Charge	239,270		239,270							239,270	53,171
15	Commodity Charge											
16	First 400 therms, per therm: non-gas portion	1,051,635		1,051,635	27,356		79,108		19,689		1,177,788	8,712,077
17	First 400 therms, per therm: gas portion	3,391,524	(545,202)	2,846,322						67,039	2,913,361	8,712,077
18	Next 1,600 therms, per therm: non-gas portion	617,331		617,331	21,369		61,794		15,381		715,875	6,805,547
19	Next 1,600 therms, per therm: gas portion	2,649,331	(425,891)	2,223,440						52,369	2,275,809	6,805,547
20	Over 2,000 therms, per therm: non-gas portion	118,261		118,261	6,117		17,688		4,402		146,468	1,947,970
21	Over 2,000 therms, per therm: gas portion	758,325	(121,904)	636,421						14,990	651,411	1,947,970
22												
23		8,825,677	(1,092,997)	7,732,680	54,842	0	158,588	0	39,472	134,398	8,119,980	
24												
25	RATE NO. 84 - Commercial and Industrial-Firm											
26												
27	Customer Charge	92,260		92,260							92,260	1,318
28	Demand Charge											
29	Per therm of daily contract demand											
30	Non-gas portion	197,996		197,996	(197,996)						0	407,114
31	Gas portion	555,165	(214,735)	340,429						1,547	341,976	407,114
32	Commodity Charge											
33	All use, per therm: non-gas portion	173,646		173,646	16,252	14,647	48,996		33,125		284,666	5,175,746
34	All use, per therm: gas portion	1,279,186	(215,518)	1,063,668						57,399	1,121,067	5,175,746
35	Released Capacity and Balancing Services Surcharge	0		0						0	0	
36												
37		2,298,253	(430,254)	1,867,999	(181,744)	14,647	48,996	0	33,125	58,946	1,839,969	

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NORTHWESTERN PUBLIC SERVICE COMPANY

Reconciliation of Rate Changes and Effects on Revenues
Changes in Revenues Since Base Rates Established

Line No	Description	Docket No NG94-008 Base Rates	PGA Changes thru 6/30/99	Current Rates	Remove Non-Gas Portion of Rate No. 84 & 86 Demand	Remove Rate No. 85 Rate Block Differential	Adjust Manufactured Gas Plant Removal Cost Tracker	Eliminate Rate No. 89	Realign Large vs Small Customer	Market Rates for Rate No 84 & 85 - Gas Costs	Proposed Rates	Annual Billing Units
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		$	$	$	$	$	$	$	$	$	$	
1	RATE NO. 85 - Commercial and Industrial-Interruptible											
2												
3	Customer Charge	88,900		88,900							88,900	1,270
4	Commodity Charge											
5	First 10,000 therms, per therm: non-gas portion	182,178		182,174	11,032	(54,384)	31,902		22,466		193,240	3,513,485
6	First 10,000 therms, per therm: gas portion	903,405	(146,302)	757,101						49,505	808,606	3,513,485
7	Over 10,000 therms, per therm: non-gas portion	37,413		37,413	3,502	3,186	10,126		7,137		61,334	1,115,150
8	Over 10,000 therms, per therm: gas portion	286,761	(46,435)	240,326						15,712	256,038	1,115,150
9												
10		1,498,741	(192,737)	1,306,004	14,534	(51,198)	42,028	0	29,823	65,217	1,408,203	
11												
12	RATE NO. 86 - (Firm) Transportation Service											
13												
14	Customer Charge	15,600		15,600				37,980			53,580	60
15	Commitment Charge											
16	Per therm of daily contract demand											
17	Non-gas portion	29,692		29,692	(29,692)						0	66,048
18	Gas portion	92,794	(35,893)	56,901						259	57,160	66,048
19	Commodity Charge, all therms per month											
20	Delivery Service	273,973		273,973	25,642	23,110	74,148	168,110	(111,059)		451,924	8,166,107
21	Standby Sales Service, per therm											
22	Non-gas portion	0		0	0	0	0				0	0
23	Gas portion	0	0	0						0	0	0
24												
25		412,059	(35,893)	376,166	(4,050)	23,110	74,148	204,070	(111,059)	259	582,644	
26												
27	RATE NO. 80 - [Interruptible Transportation Service]											
28												
29	Customer Charge	37,980		37,980				(37,980)			0	148
30	Commodity Charge, all therms per month											
31	Delivery Service	159,229		159,229	14,502	13,431	43,094	(166,110)	(84,546)		0	4,746,016
32												
33		197,189	0	197,189	14,502	13,431	43,094	(204,070)	(84,546)	0	0	
34												
35	Totals	32,570,693	(3,782,048)	28,788,647	349	(10)	659,419	0	(66)	508,454	29,956,791	
36	Less Gas Costs	22,545,580	(3,782,046)	18,763,534	0	0	0	0	0	508,454	19,271,988	
37	Add 3M Contract with Deviation	72,436		72,436							72,436	2,897,526
38	Lake Norden Line Contribution	49,100		49,100							49,100	
39												
40	Non-gas Portion of Revenues a	10,146,651	0	10,146,651	349	(10)	659,419	0	(66)	0	10,806,341	

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NORTHWESTERN PUBLIC SERVICE COMPANY

Reconciliation of Rate Changes and Effects on Revenues
Docket No. NG94-008 Rate Case Revenues, Gas Costs, Margins and Therm Billing Determinants

Line No	Rate No. and Class of Customer (a)	Annual Commodity Therms (b)	Annual Demand Therms (c)	Commodity Gas Cost Base Rate (d) $/Therm	Demand Gas Cost Base Rate (e) $/Therm
1	Rate Nos. 81/82 Residential/Small Commercial	49,936,707	0	0.38929	0.00000
2					
3	Rate No. 84 Firm Lg. Commercial/Industrial	5,175,746	407,114	0.24715	1.38366
4					
5	Rate No. 85 Int. Lg. Commercial/Industrial	4,628,635	0	0.25715	0.00000
6					
7	Rate No. 88 Agency Firm	8,166,107	68,048	Varies	1.38356
8					
9	Rate No. 89 Agency Interruptible	4,746,016	0	Varies	0.00000
10					
11					
12	Total Before 3M	72,623,211			
13					
14	3M Flex Transportation	2,897,526			
15					
16					
17	Total Throughput	75,520,737			
18					
19					
20					
21					
22					
23	Rate No. and Class of Customer	Docket No. NG94-008 Base Revenue	Commodity Gas Cost	Demand Gas Cost	Docket No. NG94-008 Non-Gas Cost Recovery	Adjustments: 3M Margin	Adjustments: Lake Norden Contribution	Docket No. NG94-008 Net Non-Gas Cost Recovery
24	(a)	(b) $	(c) $	(d) $	(e) $	(f) $	(g) $	(h) $
25								
26								
27	Rate Nos. 81/82 Residential/Small Commercial	28,164,451	19,428,182	0	8,736,269	0	0	8,736,269
28								
29	Rate No. 84 Firm Lg. Commercial/Industrial	2,298,253	1,279,186	555,165	463,902	0	0	463,902
30								
31	Rate No. 85 Int. Lg. Commercial/Industrial	1,498,741	1,190,253	0	308,488	0	0	308,488
32								
33	Rate No. 88 Agency Firm	2,156,309	1,744,250	92,794	319,265	0	0	319,265
34								
35	Rate No. 89 Agency Interruptible	2,017,562	1,698,835	0	318,727	(72,438)	(49,100)	197,189
36								
37								
38	Totals	36,135,316	25,340,706	647,959	10,146,651	(72,438)	(49,100)	10,025,113

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NORTHWESTERN PUBLIC SERVICE COMPANY

SOUTH DAKOTA NATURAL GAS COSTS

Benchmark Pricing

Month	Actual MMBtu Sales	First of Month Ventura Index	First of Month Demarc Index	Average of First of Month Ventura and Demarc Index	Commodity Cost @ 50% Ventura & 50% Demarc Index Plus 5% Fuel	Blended Index Price Plus $0.04 NNG Transportation and $0.02 CIBOLA
		$/MMBtu	$/MMBtu	$/MMBtu	$	$/MMBtu
January	1,200,920	2.00	2.05	2.03	2,559,856	2.192
February	1,381,211	1.84	1.86	1.85	2,689,727	2.007
March	1,104,859	1.94	1.98	1.96	2,279,499	2.123
April	935,999	2.11	2.16	2.14	2,103,535	2.307
May	616,994	1.91	1.99	1.95	1,266,461	2.113
June	391,083	1.93	2.03	1.98	815,099	2.144
July	272,815	2.07	2.17	2.12	608,808	2.292
August	264,475	2.07	2.08	2.08	577,669	2.244
Year to Date	6,168,356				12,900,654	2.151

Actual Pricing

Month	Total Gas Supply Cost	PGA True-up	Demand Cost	Commodity Cost	Blended Commodity Cost	Favorable (Unfavorable) Cost Variance
	$	$	$	$	$/MMBtu	$/MMBtu
January	2,992,425	(147,647)	729,551	2,410,521	2.007	0.185
February	3,368,029	(41,256)	707,356	2,699,929	1.955	0.052
March	2,660,656	(179,809)	717,021	2,323,444	2.103	0.020
April	2,508,447	(493,839)	480,087	2,522,199	2.695	(0.388)
May	1,770,762	(97,962)	524,843	1,343,881	2.178	(0.065)
June	1,330,250	(33,157)	546,806	816,601	2.088	0.056
July	1,092,297	98,241	522,845	471,211	1.727	0.565
August	1,084,236	34,881	521,246	528,109	1.997	0.247
Year to Date	17,005,102	(860,548)	4,749,755	13,115,895	2.126	0.025

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EXHIBIT

6

10-20-97 LG

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE REQUEST BY NORTHWESTERN PUBLIC SERVICE COMPANY FOR TARIFF REVISIONS	))))	ORDER APPROVING TARIFF REVISIONS AND APPROVING SETTLEMENT NG96-015

On July 2, 1996, Northwestern Public Service Company of Huron, South Dakota (NWPS), filed with the Public Utilities Commission (Commission) the following proposed tariff revisions in its natural gas rate book:

Section No.1,	26th Revised Sheet No. 1 3rd Revised Sheet No. 2
Section No. 2,	6th Revised Sheet No. 1 5th Revised Sheet No. 2
Section No. 3,	15th Revised Sheet No. 1 1st Revised Sheet No. 2 6th Revised Sheet Nos. 3.1, 6.1, and 9 2nd Revised Sheet Nos. 3.2, 3.3, 4.2, 6.3, and 13.1 5th Revised Sheet Nos. 4.1 and 9c 3rd Revised Sheet Nos. 6.2, 7, and 11 Original Sheet Nos. 6.4, 6.5, 6.6, 6.7, 6.8, 6.9, 6.10, and 6.11 10th Revised Sheet No. 8 121st Revised Sheet No. 9a 19th Revised Sheet No. 9b 140th Revised Sheet No. 11a
Section No. 5,	2nd Revised Sheet Nos. 1 and 1a Original Sheet Nos. 5.2, 6.1, 6.2, 6.3, 6.4, 6.5, 6.6, 6.7, 6.8, 7.1, 7.2, and 7.3
Section No. 6,	Original Sheet Nos. 22, 23, 24.1, 24.2, 24.3, 25.1, 25.2, 25.3, 26, 27, and 28

On July 10, 1996, PAM Natural Gas, LLC (PNG) filed a petition to intervene in this matter. Intervention was granted to PNG on July 17, 1996. Settlement was reached between the parties and staff of the Commission. A hearing on whether the settlement should be approved was held on November 5, 1996, at which time evidence on the tariff revisions and true-up of the final costs of the manufactured gas site remediation was presented. Approval was requested for implementation effective December 1,1996.

At an ad hoc meeting of November 12,1996, the Commission considered approval of the tariffs.

The Commission finds that it has jurisdiction in this matter pursuant to SDCL Chapter 49-34A, specifically 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10 and 49-34A-12. Further, the revisions, based upon the settlement reached between the parties and Commission staff, are just and reasonable and shall be approved subject to the following condition: NWPS shall make every effort to recover the manufactured gas plant remediation costs from whatever sources are available and shall report to the Commission biannually, starting six months from the date of this Order, as to the status of its efforts in collection of those costs.

As the Commission's final decision in this matter, it is therefore

ORDERED, that the Settlement Agreement reached between the parties and Commission staff is incorporated herein by reference and is approved; and it is further

ORDERED, that NWPS' revised tariffs as described above are approved upon the condition regarding reporting of collection efforts on the manufactured gas plant remediation costs and they shall be effective for service rendered on and after December 1, 1996.

Dated at Pierre, South Dakota, this 25th day of November, 1996.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delores Kaelber

Date: 11/25/96

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION

KENNETH STOFFERAHN, Chairman

JAMES A. BURG, Commissioner

LASKA SCHOENFELDER, Commissioner

RECEIVED

OCT 19 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STATE OF SOUTH DAKOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the Matter of the Application of NorthWestern Public Service For Authority to Increase Natural Gas Rates in South Dakota	))))	Docket No. NG99-002

EXHIBIT
7
10-20-99 LG

SETTLEMENT AGREEMENT BETWEEN NORTHWESTERN PUBLIC SERVICE AND COMMISSION STAFF

This Settlement Agreement is made and entered into by and between NorthWestern Public Service (the "Company"), a division of NorthWestern Corporation, and the Staff of the South Dakota Public Utilities Commission ("Staff").

I.

BACKGROUND

On June 1, 1999, the Company filed an application with the Public Utilities Commission ("Commission") for an increase in South Dakota revenue to the Company of $2,108,112 or approximately 6% based on the test year ending December 31, 1998, as adjusted. The Company cited increased costs of operation and its expanded distribution system since its last general rate increase, filed in 1994, as the reasons for the proposed change in rates.

On June 25, 1999, the Commission filed a notice of opportunity to intervene. No petitions to intervene have been received by the Commission.

The Staff submitted numerous data requests to the Company during the course of the Staff investigation. On September 24, 1999, Commission Staff filed the testimony of Robert G. Towers, David Jacobson, Martin C. Bettmann, Michele M. Farris, Keith A. Senger and Basil L. Copeland, Jr.. Commission Staff recommended an increase in Company revenue of $402,290 which reflected a disallowance related to the Nekota pipeline. During and following the receipt of the data responses from the Company, the Staff and the Company engaged in numerous discussions relating to the settlement of a variety of issues. The procedural schedule related to the Company's time to file rebuttal testimony was

suspended by the Commission based upon the representations by the Company and the Staff that a substantial agreement concerning the settlement of the proceeding had been reached.

II.

ELEMENTS OF THE SETTLEMENT AGREEMENT

Article I. Revenue Requirement

The Company and the Staff agree that, if the Commission approves this Settlement Agreement ("Agreement"), the Company will file revised rate schedules to produce an annual increase in base rate revenue levels (i.e., excluding purchased gas cost adjustment and sales taxes) of $1,279,025 applicable to retail natural gas service. The revised rate schedules shall be effective for billings rendered on and after December 1, 1999, provided there is Commission approval of this Agreement and the revised rate schedules.

Article II. Rate Design

The agreed to change in rates would affect customer classes by the following percentages:

Class	% Increase
Residential – Rate 81	3.8
Small Commercial – Rate 82	3.9
Large Commercial/Industrial Firm Rate 84 (Option A)	1.6
Large Commercial/Industrial Rate 84 (Option B)	1.5
Large Commercial/Industrial Interruptible – Rate 85 (Option A)	1.8
Large Commercial/Industrial Interruptible – Rate 85 (Option B)	1.4
Transportation – Rate 87 (Option A)	22.5
Transportation – Rate 87 (Option B)	9.1
Contracts with Deviations	1.5
Total South Dakota	3.8

Article III. Other Conditions

The parties agree to a return on common equity of 10.25% and that Company's capital structure shall be based on its stand alone capital structure rather than a consolidated capital structure.

It is further agreed by the parties that the Nekota pipeline issue which was raised by Commission Staff has been eliminated from the base rate determination, and alternatively will be heard as a Purchase Gas Adjustment request before the Public Utilities Commission on October 20, and October 21, 1999 as a separate proceeding from the base rate determination.

It is further agreed by the parties that the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, contracts between the Company and any separate affiliated company that does business with the Company, related to the Company's utility business in South Dakota. Such contracts will identify the products and services to be provided by the affiliate to the Company and will provide that the pricing of such products and services shall be based upon the affiliate's costs, which costs include a reasonable profit for the affiliate. The Company will maintain and, upon Commission or Commission Staff request, furnish information supporting the basis of the pricing of such products and services, whether based on costs of labor and materials provided or specific allocations of joint or common costs. In addition, the Company will provide to the Commission for its information, in a filing made no later than December 1, 1999, an explanation of NorthWestern Corporation expenses or allocations charged to the Company. Thereafter, June 30th of each year (beginning June 30, 2000), the Company will file with the Commission any new or revised contracts with each affiliate doing business with the Company and a statement of all transactions between the Company and each affiliate during the preceding calendar year, as well as any changes in the methodology for the charging of any NorthWestern Corporation expenses or allocations to the Company.

Article IV General Conditions

1. It is agreed that this Agreement is a negotiated dollar settlement and establishes no principles or precedent and shall not be deemed to foreclose the Company or the Staff or any other person from making any contention in any proceeding or investigation, including the right of the Staff or any other interested person to seek a rate change if justified on any basis.

2. Approval of this Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this proceeding.

3. The Agreement is expressly conditioned upon the Commission's acceptance of all the provisions thereof, without change or condition which is unacceptable to any party.

4. Discussions between the Company and the Staff which produced this Agreement have been conducted with the customary understanding that all offers of settlement and discussions relating thereto are privileged and shall not be used in any manner in connection with this proceeding or otherwise, except as required by law.

5. This Agreement includes all terms of Settlement and is submitted on the condition that in the event the Commission imposes any change in or condition to this Agreement which is unacceptable to any party, this Agreement shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding or be used for any other purpose.

6. This Agreement shall be binding upon the parties hereto, and upon their successors, assigns, agents and representatives.

7. It is understood that the Staff enters into this Agreement for the benefit of the Company's South Dakota natural gas customers affected hereby.

8. This Agreement is entered into by and between the Company and the Staff by their respective agents who represent that they are fully authorized to do so on behalf of their principals.

Staff of the South Dakota
Public Utilities Commission

By Karen E. Cremer
Title Staff Attorney
Dated: October 19, 1999

NorthWestern Public Service
a division of NorthWestern Corporation

By [signature]
Title President & CEO
Dated October 19, 1999

Attached to this Settlement Agreement and incorporated herein are the attached schedule

Northwestern Public Service
South Dakota - Gas
Revenue Increase
Per Staff

Line No.	RATE STEP	THERMS (A)	THERMS (B)	TOTAL MARGIN (C) Test Year Revenue	REVISED (D) Proposed Revenue	INCREASE (F) Revenue (Inc./Dec.)	PERCENT INCREASE (G) Percent (Inc./Dec.)
	REVENUE INCREASE by RATE CODE						
1	RATE 81	33,197,790	33,197,790	20,189,402	20,961,369	771,967	3.8%
2	RATE 82	15,868,880	15,868,880	8,226,248	8,546,645	320,397	3.9%
3	RATE 84 (OPTION A&B)	5,936,020	5,936,020	2,235,630	2,269,986	34,356	1.5%
4	RATE 85 (OPTION A&B)	4,425,500	4,425,500	1,431,062	1,455,934	24,871	1.7%
5	RATE 87 (OPTION A&B)	29,121,130	29,121,130	1,211,082	1,334,781	123,699	10.2%
6	COMBINED RATE 84, 85, and 87 Sum of Line 3, 4, and 5	39,482,650	39,482,650	4,877,775	5,060,701	182,926	3.8%
7	CONTRACTS with DEVIATIONS	10,400,310	10,400,310	196,440	199,376	2,936	1.5%
8	TOTAL (Sum of Lines 1, 2, 6, and 7)	98,947,630	98,947,630	$ 33,489,865	$ 34,768,090	$ 1,278,226	3.8%

Northwestern Public Service
South Dakota - Gas
Residential - Rate 81 and Small Commercial - Rate 82
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Residential - Rate Code 81**									
2										
3		ALL THERMS CURRENTLY (FIRST 30)	Therms	9,414,430	9,414,430	0.2000	0.2055	1,882,886	1,934,665	51,779
4		EXCESS	Therms	23,783,360	23,783,360	0.1220	0.1270	2,901,570	3,020,487	118,917
5										
6		CUSTOMER CHARGE	BILL	400,847	400,847	4.50	6.00	1,803,812	2,405,082	601,271
7										
8		AD VALOREM TAX ADJUSTMENT		33,197,790	33,197,790	0.0156	0.0156	517,886	517,886	0
9		MGP REMOVAL COST ADJUSTMENT		33,197,790	33,197,790	0.0140	0.0140	464,769	464,769	0
10		GAS COST COMMODITY CHARGE		33,197,790	33,197,790	0.2043	0.2043	6,782,308	6,782,308	0
11		GAS COST DEMAND CHARGE		33,197,790	33,197,790	0.1758	0.1758	5,838,171	5,838,171	0
12										
13		TOTAL		33,197,790	33,197,790			20,189,402	20,961,369	771,967
								6,588,267		
14	**Small Commercial - Rate Code 82**									
15										
16		ALL THERMS CURRENTLY (FIRST 400)	Therms	8,490,570	8,490,570	0.1141	0.1309	968,774	1,111,416	142,642
17		NEXT 1,600	Therms	6,108,520	6,108,520	0.0841	0.0891	513,558	544,091	30,533
18		EXCESS	Therms	1,269,790	1,269,790	0.0541	0.0541	68,698	68,698	0
19										
20		CUSTOMER CHARGE	BILL	58,889	58,889	4.50	7.00	265,001	412,223	147,223
21										
22		AD VALOREM TAX ADJUSTMENT		15,866,880	15,866,880	0.0099	0.0099	157,082	157,082	0
23		MGP REMOVAL COST ADJUSTMENT		15,866,880	15,866,880	0.0140	0.0140	222,136	222,136	0
24		GAS COST COMMODITY CHARGE		15,866,880	15,866,880	0.2043	0.2043	3,241,604	3,241,604	0
25		GAS COST DEMAND CHARGE		15,866,880	15,866,880	0.1758	0.1758	2,789,398	2,789,398	0
26										
27		TOTAL		15,866,880	15,866,880			8,226,248	8,546,645	320,397

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Firm - Rate 84 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial Firm - Rate									
1	**Code 84 (Option A)**									
2										
3		ALL THERMS	Therms	5,505,570	5,505,570	0.0364	0.0388	200,403	213,616	13,213
4										
5		CUSTOMER CHARGE	BILL	1,963	1,963	70.00	80.00	137,410	157,040	19,630
6										
7		AD VALOREM TAX ADJUSTMENT		5,505,570	5,505,570	0.0064	0.0064	35,236	35,236	0
8		MGP REMOVAL COST ADJUSTMENT		5,505,570	5,505,570	0.0140	0.0140	77,078	77,078	0
9		GAS COST COMMODITY CHARGE		5,505,570	5,505,570	0.2300	0.2300	1,266,281	1,266,281	0
10		GAS COST DEMAND CHARGE		425,480	425,480	0.8700	0.8700	370,168	370,168	0
11		RELEASE CAPACITY/BALANCING SURCHARGE		680,040	680,040	0.0170	0.0170	11,561	11,561	0
12		SUBTOTAL		5,505,570	5,505,570			2,098,136	2,130,979	32,843
	Large Commercial/Industrial Firm - Rate									
13	**Code 84 (Option B)**									
14										
15		ALL THERMS	Therms	430,450	430,450	0.0180	0.0204	7,748	8,781	1,033
16										
17		CUSTOMER CHARGE	BILL	24	24	260.00	280.00	6,240	6,720	480
18										
19		AD VALOREM TAX ADJUSTMENT		430,450	430,450	0.0042	0.0042	1,808	1,808	0
20		MGP REMOVAL COST ADJUSTMENT		430,450	430,450	0.0140	0.0140	6,026	6,026	0
21		GAS COST COMMODITY CHARGE		430,450	430,450	0.2300	0.2300	99,004	99,004	0
22		GAS COST DEMAND CHARGE		18,120	18,120	0.8700	0.8700	15,764	15,764	0
23		RELEASE CAPACITY/BALANCING SURCHARGE		53,180	53,180	0.0170	0.0170	904	904	0
		SUBTOTAL		430,450	430,450			137,494	139,007	1,513
24										
25		TOTAL		5,936,020	5,936,020			$2,235,630	$2,269,986	$34,356

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
	Large Commercial/Industrial									
1	Interruptible - Rate Code 85 (Option A)									
2										
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451
4										
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290
6										
7		AD VALOREM TAX ADJUSTMENT		3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0
8		MGP REMOVAL COST ADJUSTMENT		3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0
9		GAS COST COMMODITY CHARGE		3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0
10		RELEASE CAPACITY/BALANCING SURCHARGE		3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741
	Large Commercial/Industrial									
12	Interruptible - Rate Code 85 (Option B)									
13										
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171
15										
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960
17										
18		AD VALOREM TAX ADJUSTMENT		487,770	487,770	0.0042	0.0042	2,049	2,049	0
19		MGP REMOVAL COST ADJUSTMENT		487,770	487,770	0.0140	0.0140	6,829	6,829	0
20		GAS COST COMMODITY CHARGE		487,770	487,770	0.2300	0.2300	112,187	112,187	0
21		RELEASE CAPACITY/BALANCING SURCHARGE		487,770	487,770	0.0170	0.0170	8,292	8,292	0
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131
23										
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87 (Option A and B)
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	Transportation - Rate Code 87 (Option A)									
2										
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191
4										
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720
6										
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0
10	SUBTOTAL			1,329,490	1,329,490			97,355	119,266	21,911
11	Transportation - Rate Code 87 (Option B)									
12										
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	566,949	66,700
14										
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320
16										
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0
20	SUBTOTAL			27,791,640	27,791,640			1,113,727	1,215,515	101,788
21										
22		TOTAL		29,121,130	29,121,130			1,211,082	1,334,781	123,699

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)
1	**Contracts with Deviations**									
2										
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320
4										
5		CUSTOMER CHARGE	BILL	36	36	260.00	330.00	9,360	11,880	2,520
6										
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)
10										
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
1	CUSTOMER CHARGE	$4.60	$6.00
2	FIRST 30 THERMS	$0.20000	$0.20550
3	EXCESS THERMS	$0.12200	$0.12700
4	PGA and OTHER ADJ.	$0.40970	$0.40970

Residential - Rate Code 81

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
5	0	$4.60	$6.00	$1.50	33.33%
6	10	10.60	12.15	1.66	14.67%
7	25	19.74	21.38	1.64	8.29%
8	50	33.43	35.19	1.77	5.26%
9	75	46.72	48.61	1.89	4.05%
10	80	49.38	51.29	1.92	3.88%
11	100	60.01	62.03	2.02	3.36%
12	125	73.30	75.44	2.14	2.92%
13	150	86.60	88.86	2.27	2.62%
14	175	99.89	102.28	2.39	2.39%
15	200	113.18	115.70	2.52	2.22%
16	225	126.47	129.11	2.64	2.09%
17	250	139.77	142.53	2.77	1.98%
18	300	166.35	169.37	3.02	1.81%
19	400	219.52	223.04	3.52	1.60%
20	500	272.69	276.71	4.01	1.47%

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	196	$110.80	$113.29	$2.49	2.2%
FEB	166	$95.22	$97.57	$2.35	2.5%
MAR	148	$85.71	$87.97	$2.26	2.6%
APR	126	$73.80	$75.95	$2.14	2.9%
MAY	49	$32.65	$34.40	$1.76	5.4%
JUN	23	$18.81	$20.44	$1.63	8.7%
JUL	18	$15.77	$17.37	$1.60	10.2%
AUG	15	$13.58	$15.17	$1.58	11.6%
SEP	14	$13.27	$14.85	$1.58	11.9%
OCT	32	$23.76	$25.43	$1.67	7.0%
NOV	82	$50.27	$52.19	$1.92	3.8%
DEC	116	$69.77	$71.88	$2.11	3.0%
TOTAL	986	$603.41	$626.51	$23.09	3.8%

AVERAGE MONTHLY USE = 82 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
21	CUSTOMER CHARGE	$4.50	$7.00
22	FIRST 400 THERMS	$0.11410	$0.13090
23	NEXT 1,600 THERMS	$0.06410	$0.08910
24	EXCESS THERMS	$0.05410	$0.05410
25	PGA and OTHER ADJ.	$0.40970	$0.40970

SMALL COMMERCIAL - Rate Code 82

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
26	0	4.50	7.00	$2.50	55.56%
27	50	30.69	34.03	3.34	10.88%
28	100	56.88	61.06	4.18	7.35%
29	200	109.26	115.12	5.86	5.36%
30	350	187.83	196.21	8.38	4.46%
31	500	263.40	273.12	9.72	3.69%
32	750	386.85	397.82	10.97	2.84%
33	1000	510.30	522.52	12.22	2.39%
34	1500	757.20	771.92	14.72	1.94%
35	2000	1,004.10	1,021.32	17.22	1.71%
36	2500	1,236.00	1,253.22	17.22	1.39%
37	3,000	1,467.90	1,485.12	17.22	1.17%
38					
39					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	621	316.57	325.79	9.22	2.9%
FEB	577	286.21	295.43	9.22	3.1%
MAR	503	261.61	270.83	9.22	3.5%
APR	397	212.54	221.71	9.17	4.3%
MAY	138	76.60	81.42	4.81	6.3%
JUN	68	40.28	43.93	3.65	9.1%
JUL	60	35.92	39.43	3.51	9.8%
AUG	54	32.83	36.24	3.41	10.4%
SEP	50	30.92	34.27	3.35	10.8%
OCT	90	51.90	55.92	4.02	7.7%
NOV	261	141.25	148.13	6.89	4.9%
DEC	394	210.73	219.85	9.11	4.3%
TOTAL	3,214	$1,707	$1,783	$75.58	4.4%

AVERAGE MONTHLY USE = 268 Therms

Northwestern Public Service
South Dakota - Gas
Rate Code 81, 82, and 84
Rate Comparison
Per Staff

LINE NO.		PRESENT	PROPOSED
38	CUSTOMER CHARGE	$70.00	$80.00
39	ALL THERMS	$0.03640	$0.03880
40	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION A)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
41	0	70.00	80.00	$10.00	14.29%
42	250	141.70	152.30	10.60	7.48%
43	500	213.40	224.60	11.20	5.25%
44	750	285.10	296.90	11.80	4.14%
45	1,000	356.80	369.20	12.40	3.48%
46	1,500	500.20	513.60	13.60	2.72%
47	2,000	643.60	658.40	14.80	2.30%
48	3,000	930.40	947.60	17.20	1.85%
49	4,000	1,217.20	1,236.80	19.60	1.61%
50	5,000	1,504.00	1,526.00	22.00	1.46%
51	6,000	1,790.80	1,815.20	24.40	1.36%
52	7,000	2,077.60	2,104.40	26.80	1.29%
53	8,000	2,364.40	2,393.60	29.20	1.23%
54					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	6,298	1,876.18	1,901.29	25.11	1.3%
FEB	5,230	1,569.94	1,592.49	22.55	1.4%
MAR	4,715	1,422.15	1,443.48	21.32	1.5%
APR	4,008	1,219.43	1,239.04	19.62	1.6%
MAY	2,136	683.28	698.41	15.13	2.2%
JUN	392	182.53	193.47	10.94	6.0%
JUL	1,376	464.76	478.07	13.30	2.9%
AUG	737	281.46	293.23	11.77	4.2%
SEP	658	258.59	270.17	11.58	4.5%
OCT	1,287	439.09	452.18	13.09	3.0%
NOV	2,606	875.33	892.07	16.74	1.9%
DEC	3,471	1,085.37	1,083.70	18.33	1.7%
TOTAL	33,118	$10,338	$10,538	$199.48	1.9%

AVERAGE MONTHLY USE = 2,760 Therms

LINE NO.		PRESENT	PROPOSED
55	CUSTOMER CHARGE	$260.00	$280.00
56	ALL THERMS	$0.01800	$0.02040
57	PGA and OTHER ADJ.	$0.25040	$0.25040

LARGE COMMERCIAL/INDUSTRIAL FIRM - RATE CODE 84 (OPTION B)

	THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	% INCREASE/ (DECREASE)
	(A)	(B)	(C)	(D)	(E)
58	0	260.00	280.00	$20.00	7.69%
59	250	327.10	347.70	20.60	6.30%
60	500	394.20	415.40	21.20	5.38%
61	1,000	528.40	550.80	22.40	4.24%
62	2,500	931.00	957.00	26.00	2.79%
63	5,000	1,602.00	1,634.00	32.00	2.00%
64	10,000	2,944.00	2,988.00	44.00	1.49%
65	20,000	5,628.00	5,696.00	68.00	1.21%
66	35,000	9,654.00	9,758.00	104.00	1.08%
67	50,000	13,680.00	13,820.00	140.00	1.02%
68	60,000	16,364.00	16,528.00	164.00	1.00%
69	70,000	19,048.00	19,238.00	188.00	0.99%
70	75,000	20,390.00	20,590.00	200.00	0.98%
71					

MONTH	AVERAGE THERMS	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE/ (DECREASE)	PERCENT INCREASE/ (DECREASE)
(F)	(G)	(H)	(I)	(J)	(K)
JAN	70,064	19,065.09	19,253.24	188.15	1.0%
FEB	32,177	8,896.28	8,993.51	97.22	1.1%
MAR	28,048	7,787.98	7,875.29	87.31	1.1%
APR	19,295	5,438.85	5,505.16	66.31	1.2%
MAY	12,867	3,713.40	3,764.26	50.86	1.4%
JUN	5,147	1,641.43	1,673.79	32.35	2.0%
JUL	1,253	598.44	619.45	23.01	3.9%
AUG	377	381.19	392.09	20.90	5.8%
SE	611	477.87	499.82	21.95	4.8%
OCT	3,412	1,175.79	1,203.98	28.19	2.4%
NOV	10,388	3,047.62	3,092.55	44.93	1.5%
DEC	31,389	8,684.51	8,779.84	95.33	1.1%
TOTAL	215,224	$60,886	$61,643	$756.54	1.2%

AVERAGE MONTHLY USE = 17,935 Therms

Northwestern Public Service
South Dakota - Gas
Large Commercial/Industrial Interruptible - Rate 85
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
	Large Commercial/Industrial										
1	Interruptible - Rate Code 85 (Option A)										
2											
3		ALL THERMS	Therms	3,937,730	3,937,730	0.0364	0.0388	143,333	152,784	9,451	
4											
5		CUSTOMER CHARGE	BILL	1,329	1,329	70.00	80.00	93,030	106,320	13,290	
6											
7		AD VALOREM TAX ADJUSTMENT		3,937,730	3,937,730	0.0064	0.0064	25,201	25,201	0	
8		MGP REMOVAL COST ADJUSTMENT		3,937,730	3,937,730	0.0140	0.0140	55,128	55,128	0	
9		GAS COST COMMODITY CHARGE		3,937,730	3,937,730	0.2300	0.2300	905,678	905,678	0	
10		RELEASE CAPACITY/BALANCING SURCHARGE		3,416,180	3,416,180	0.0170	0.0170	58,075	58,075	0	
11		SUBTOTAL		3,937,730	3,937,730			1,280,446	1,303,187	22,741	1.8%
	Large Commercial/Industrial										
12	Interruptible - Rate Code 85 (Option B)										
13											
14		ALL THERMS	Therms	487,770	487,770	0.0180	0.0204	8,780	9,951	1,171	
15											
16		CUSTOMER CHARGE	BILL	48	48	260.00	280.00	12,480	13,440	960	
17											
18		AD VALOREM TAX ADJUSTMENT		487,770	487,770	0.0042	0.0042	2,049	2,049	0	
19		MGP REMOVAL COST ADJUSTMENT		487,770	487,770	0.0140	0.0140	6,829	6,829	0	
20		GAS COST COMMODITY CHARGE		487,770	487,770	0.2300	0.2300	112,187	112,187	0	
21		RELEASE CAPACITY/BALANCING SURCHARGE		487,770	487,770	0.0170	0.0170	8,292	8,292	0	
22		SUBTOTAL		487,770	487,770			150,616	152,747	2,131	1.4%
23											
24		TOTAL		4,425,500	4,425,500			1,431,062	1,455,934	24,871	1.7%

Northwestern Public Service
South Dakota - Gas
Transportation - Rate 87
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	Transportation - Rate Code 87 (Option A)										
2											
3		ALL THERMS	Therms	1,329,490	1,329,490	0.0364	0.0388	48,393	51,584	3,191	
4											
5		CUSTOMER CHARGE	BILL	312	312	70.00	130.00	21,840	40,560	18,720	
6											
7	EXTENDED SERVICE RIDER DISCOUNT							0	0	0	
8	AD VALOREM TAX ADJUSTMENT			1,329,490	1,329,490	0.0064	0.0064	8,509	8,509	0	
9	MGP REMOVAL COST ADJUSTMENT			1,329,490	1,329,490	0.0140	0.0140	18,613	18,613	0	
10	SUBTOTAL			1,329,490	1,329,490			97,355	119,266	21,911	22.5%
11	Transportation - Rate Code 87 (Option B)										
12											
13		ALL THERMS	Therms	27,791,640	27,791,640	0.0180	0.0204	500,250	566,949	66,700	
14											
15		CUSTOMER CHARGE	BILL	576	576	260.00	330.00	149,760	190,080	40,320	
16											
17	EXTENDED SERVICE RIDER DISCOUNT							(42,090)	(47,322)	(5,232)	
18	GAS COST COMMODITY CHARGE			27,791,640	27,791,640	0.0042	0.0042	116,725	116,725	0	
19	RELEASE CAPACITY/BALANCING SURCHARGE			27,791,640	27,791,640	0.0140	0.0140	389,083	389,083	0	
20	SUBTOTAL			27,791,640	27,791,640			1,113,727	1,215,515	101,788	9.1%
21											
22	TOTAL			29,121,130	29,121,130			1,211,082	1,334,781	123,699	10.2%

Northwestern Public Service
South Dakota - Gas
Contracts with Deviations
Rate Comparison
Per Staff

LINE NO.	CLASS OF SERVICE & RATE SCHEDULE CODE (A)	TYPE OF CHARGE	UNIT (B)	PRESENT QUANTITIES (C)	PROPOSED QUANTITIES (D)	PRESENT RATES (E)	PROPOSED RATES (F)	PRESENT REVENUES (G)	PROPOSED REVENUES (H)	REVENUE INC./DEC. (I)	PERCENT CHANGE
1	Contracts with Deviations										
2											
3		ALL THERMS	Therms	10,400,310	10,400,310	0.0069	0.0077	71,762	80,082	8,320	
4											
5		CUSTOMER CHARGE	BILL	36	36	260.00	330.00	9,360	11,880	2,520	
6											
7	EXTENDED SERVICE RIDER DISCOUNT							(1,166)	(1,166)	0	
8	AD VALOREM TAX ADJUSTMENT			10,400,310	10,400,310	0.0042	0.0042	43,681	43,681	0	
9	MGP REMOVAL COST ADJUSTMENT			10,400,310	10,400,310	0.0070	0.0062	72,802	64,898	(7,904)	
10											
11		TOTAL		10,400,310	10,400,310			196,440	199,376	2,936	1.5%

NG99-002

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#4

Northwestern Public Service

Growing Stronger . . . Serving Better

Presented to

South Dakota Public Utilities Commission and Staff

Presentation Agenda

Welcome	*Warren Lotsberg*
Changing to Serve Tomorrow's Customer	*Merle Lewis*
Our Future is the Customer	*Tom Gulbranson*
Our Infrastructure: Reliable, Efficient, Economical	*Art Donnell*
Administration: Serving the Internal Customer	*Alan Dietrich*
Retaining and Building Market Share	*Rod Leyendecker*
Comparing Rates – Why is it so Confusing?	*Tom Hitchcock*
Expanding Our Future	*Dan Newell*
Growing Stronger... Serving Better...	*Dick Hylland*

EXHIBIT 9

Retaining and Building Market Share

Mechanisms and Strategies to Protect Customers and Margins

- ✓ Retain delivery services to customers on our system
  - Rate tariff maintenance
    - ⇨ Protect margins
    - ⇨ Enhance customers' choice (unbundle)
- ✓ Provide support to Energy Services and Energy Operations
  - Tariff applications
  - Energy procurement
  - Energy sales and transportation

Retaining and Building Market Share

Strategies to Attract New Customers and New Revenues

- ✓ Develop marketing affiliates to expand market for energy and energy solutions
- ✓ Optimization of opportunities
  - Contracted services
  - Gas pipelines
  - Electric generation
  - All supporting assets

Retaining and Building Market Share

Competitive Intelligence

- ✓ Intelligence gathering and analysis
- ✓ Integrate intelligence into strategic opportunities

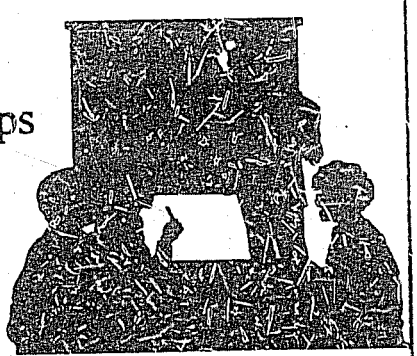


Northwestern –
Growing Stronger . . . Serving Better

Retaining and Building Market Share

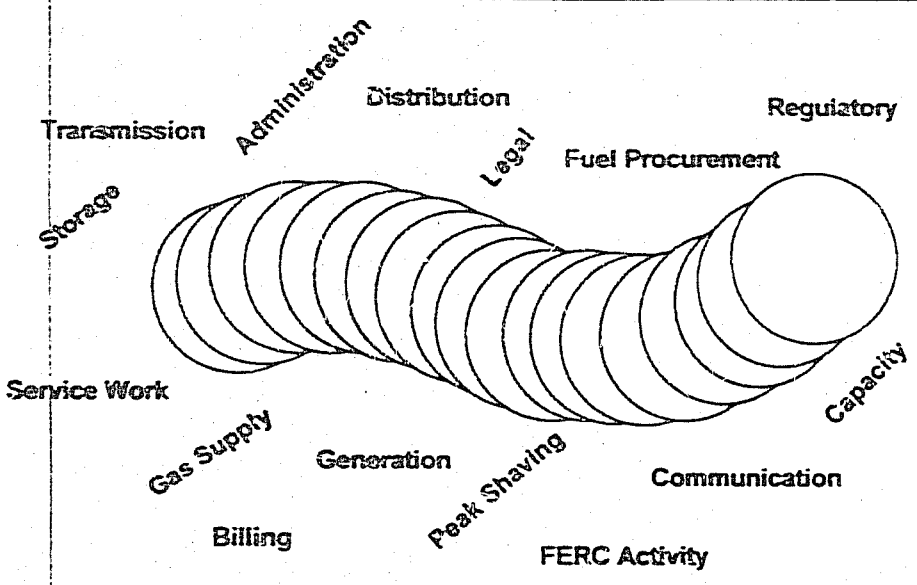
Critical Areas

- ✓ Industry knowledge and research
- ✓ Disaggregation studies
- ✓ Alliances and partnerships
- ✓ Proactively anticipating industry changes



Northwestern –
Growing Stronger . . . Serving Better

Full-Service Regulated Utility Business



Pipes and Wires Business

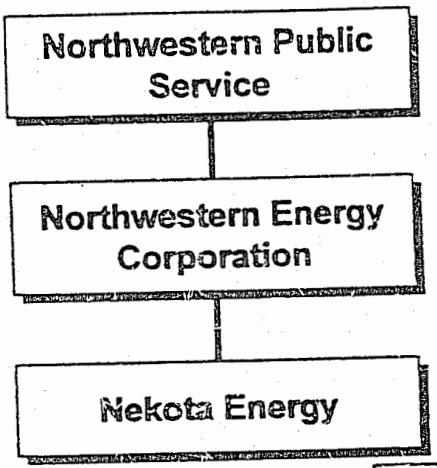


Transmission Services
Fuel Storage
Fuel Procurement
Regulatory Services
FERC Activities
Service Work
Administrative Services

Capacity Services
Communication Services
Generation Services
Energy Procurement Services
Storage Services
Legal Services
Billing Services

Retaining and Building Market Share

The Foundation of Market Development



Manager Rates & Regulation – Tom Hitchcock

Comparing Rates —

"Why is it so Confusing?"

NORTHWESTERN PUBLIC SERVICE

Exhibit____(DAJ-3)
Schedule 1

South Dakota - Gas
Nekota Resources Pipeline Adjustment
Test Year Ended 12-31-99

Line No.	(A)	(B)
1	Rate of return	8.53%
2	Federal income taxes	2.54%
3	Fixed charge factor	11.07%
4	Nekota Resources' original investment	$1,185,000
5	Service period (years)	20
6	Levelized fixed charge cost of service	$149,489
7	Property taxes	$23,326
8	Annual charges	$172,815
9	Allocation to NWPS - South Dakota	100.00%
10	NWPS's share of levelized cost	$172,815
11	NEC's charges as filed	576,000
12	Adjustment to affiliate charges	($403,185)

EXHIBIT
A
10-20-99 LG

NORTHWESTERN PUBLIC SERVICE COMPANY
33 THIRD ST SE PO BOX 1318
HURON, SOUTH DAKOTA 57350-1318
TELEPHONE (605) 352-8411
FAX (605) 353-8286

November 4, 1996

RECEIVED
NOV 0 1996
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard Jr., Executive Director
South Dakota Public Utilities Commission
State Capitol Building
Pierre, South Dakota 57501

Dear Mr. Bullard:

Enclosed herein are three (3) copies of 121st Revised Sheet No. 9a of Northwestern's Gas Tariff.

Sheet No. 9a reflects changes in the costs of purchased gas from the Company's wholesale suppliers, effective November 1, 1996, along with gas cost "true up" balances.

The effect of Sheet No. 9a for a typical space heating customer using 150 therms per month would be an increase in the cost from $72.90 to $88.41, about 21 1/4%. Application of this new PGA will begin with billings on and after November 1, 1996.

Should you have any questions regarding the above changes, please advise.

Sincerely,

Jeff J. Decker

Jeff J. Decker
Director-Price Analysis

JD/las

Enclosures

EXHIBIT
B

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE COMPANY
HURON
SOUTH DAKOTA

Section No. 3
121st Revised Sheet No. 9a
Canceling 120th Revised Sheet No. 9a

Purchased Gas Cost Adjustment

	Cumulative Adjustment (Per Therm)
Rate No. 81 - Residential Gas Service	$0.02182
Rate No. 82 - General Gas Service	$0.02182
Rate No. 84 - Commercial and Industrial	
Demand Charge	$(0.58925)
Commodity Charge	$0.02657
Rate No. 85 - Commercial and Industrial	
Interruptible	$0.02657
Rate No. 88 - Firm Delivery Service	
Commitment Charge	$(0.58925)
Standby Sales Service	$0.02657

Reason for Current Adjustment:

To reflect changes in the cost of gas as measured from the base costs of gas included in base rates effective November 15, 1994.

Date Filed: November 4, 1996

Billings on and after
Effective Date: November 1, 1996

R. F. Levendecker
Issued By: Vice President-Market Development

NG99-002

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#5

NORTHWESTERN PUBLIC SERVICE COMPANY

33 THIRD ST SE PO BOX 1318
HURON, SOUTH DAKOTA 57350-1318
TELEPHONE (605) 352-8411
FAX (605) 353-8286

December 3, 1996

RECEIVED
DEC [illegible] 1996
SOUTH DA[illegible]A PUBLIC
UTILITIES [illegible]SION

Mr. William Bullard Jr., Executive Director
South Dakota Public Utilities Commission
State Capitol Building
Pierre, South Dakota 57501

Dear Mr. Bullard:

Enclosed herein are three (3) copies of 123rd Revised Sheet No. 9a of Northwestern's Gas Tariff.

Sheet No. 9a reflects changes in the costs of purchased gas from the Company's wholesale suppliers, effective December 1, 1996, along with gas cost "true up" balances.

The effect of Sheet No. 9a for a typical space heating customer using 150 therms per month would be an increase in the cost from $88.41 to $105.26, about 19%. Application of this new PGA will begin with billings on and after December 1, 1996.

Should you have any questions regarding the above changes, please advise.

Sincerely,

Jeff J. Decker

Jeff J. Decker
Director-Price Analysis

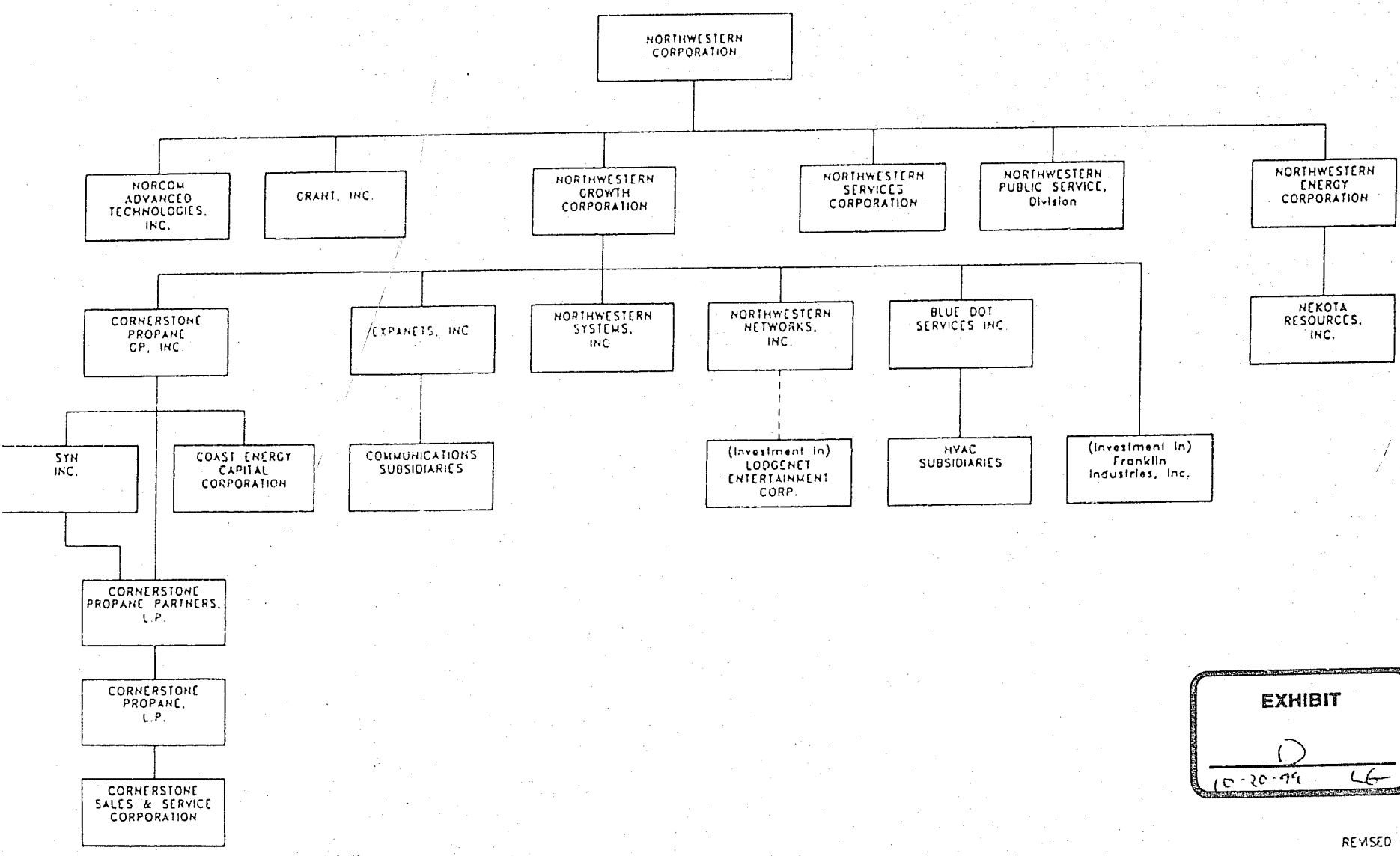
JD/las

Enclosures

EXHIBIT
C
10-20-99 LG

NorthWestern™

PARTNER ENTITIES



EXHIBIT

D

10-20-99 LG

REVISED 06/01/99

NG99-002

NorthWestern
PUBLIC SERVICE

600 Market Street W
Huron, SD 57350-1500
Telephone: 605-352-8411
Facsimile: 605-353-7519
Internet: www.northwestern.com

November 5, 1999

RECEIVED
NOV 08 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. Dave Jacobson
S.D. Public Utilities Commission
500 East Capitol Ave.
Pierre, SD 57501

Dear Dave:

Enclosed are the tariff schedules reflecting the settlement base rates approved by the commission on November 1, 1999.

Sincerely,

Jeff J. Decker/lak

Jeff J. Decker

JJD/lak

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 2
7th Revised Sheet No. 1
Canceling 6th Revised Sheet No. 1

PRELIMINARY STATEMENT

Territory Served

Northwestern Public Service Company ("Company") provides gas service at retail to the following communities and their immediate environs in eastern South Dakota.

Aberdeen	Dimock	Lake Norden	Redfield
Alexandria	Doland	Lake Preston	Revillo
Altamont	Estelline	Madison	Scotland
Arlington	Ethan	Marion	Spencer
Aurora	Ferney	Mellette (N)	Tripp
Big Stone City	Frankfort	Menno	Turton
Bristol	Goodwin	Milbank	Verdon
Brookings	Groton	Mitchell	Vienna
Bryant	Hayti (N)	Monroe	Volga
Canistota	Hazel	Mt. Vernon	Warner
Castlewood	Holmquist	Oldham	Webster
Clark	Howard	Olivet	Willow Lake
Clear Lake	Huron	Parker	Wolsey (N)
Conde	Kranzburg	Parkston	Yale
DeSmet	Labolt	Raymond	

A map showing communities served with gas service at retail follows this sheet.

Types and Classes of Service

1. Residential Gas Service
2. General Gas Service
3. Commercial and Industrial Firm Sales Service
4. Commercial and Industrial Interruptible Sales Service
5. Transportation Service, including Customer Balancing and Standby Service Options

All service is furnished under the provisions of the Company's General Terms and Conditions set forth in Section No. 5 of these tariff schedules.

(continued)

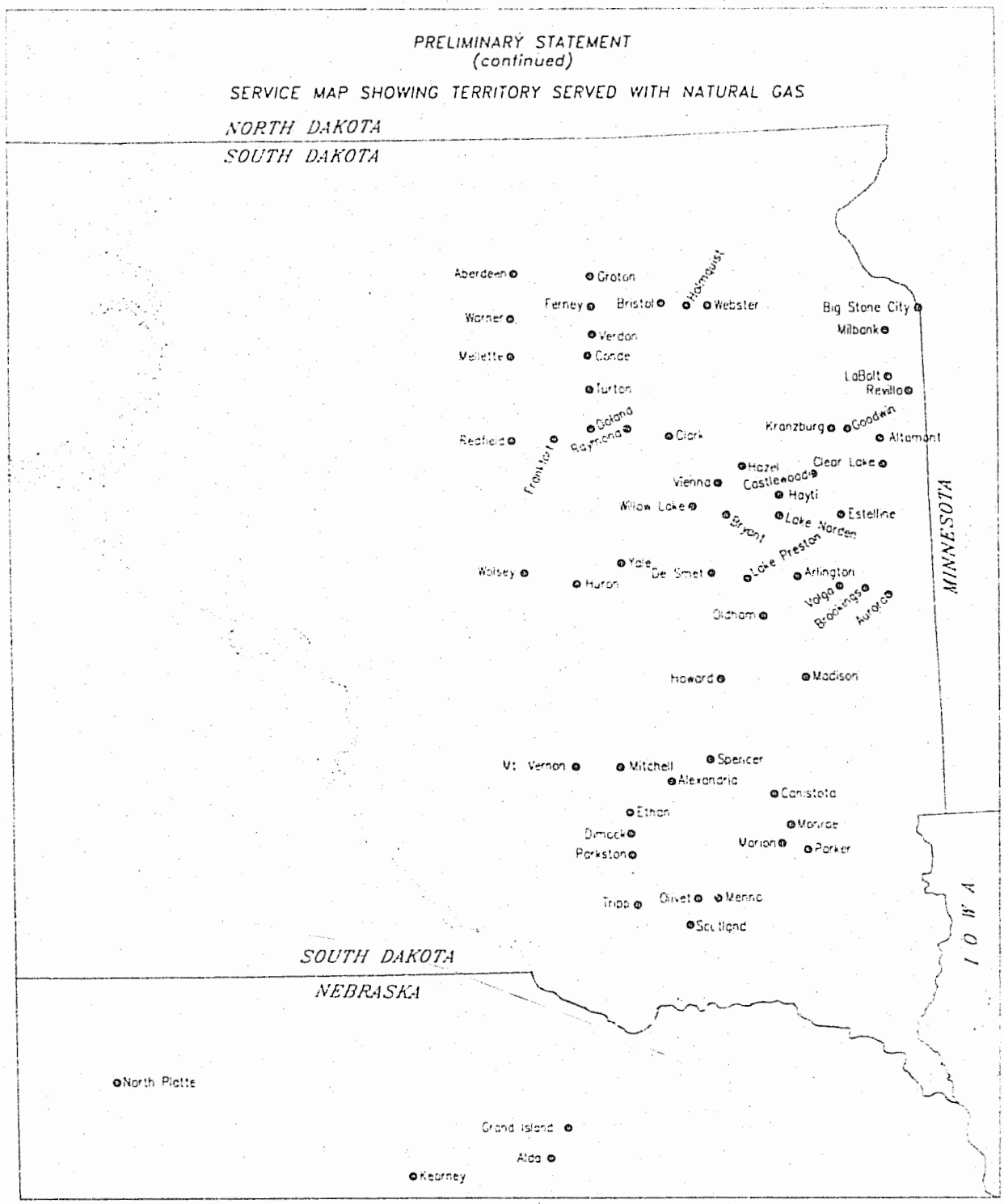
SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 2
6th Revised Sheet No. 2
Canceling 5th Revised Sheet No. 2

PRELIMINARY STATEMENT
(continued)

SERVICE MAP SHOWING TERRITORY SERVED WITH NATURAL GAS



(N)

(N)

Date Filed: November 5, 1999 **Effective Date:** December 1, 1999

Michael J. Hanson
Issued By: President & CEO

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
17th Revised Sheet No. 1
Canceling 16th Revised Sheet No. 1

CLASS OF SERVICE: Residential Gas Service — Rate No. 81
RATE DESIGNATION: Firm Sales

1. **Applicability**

This rate is available to domestic customers whose maximum requirements for natural gas are not more than 200 therms per day. The name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements, based on 10 hours use per day.

2. **Territory**

The area served with natural gas by the Company in South Dakota.

3. **Rates**

Monthly Charges:			
Customer Charge per Meter:	$	6.00	(I)
Non-Gas Commodity Charge:			
First 30 therms, per therm	$	0.2055	(I)
Over 30 therms, per therm	$	0.1270	(I)
Standby Capacity Charge - December through March:	$	12.00	
Minimum Monthly Bill:	$	6.00	(I)

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. **Other Provisions**

The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: November 5, 1999
Service on and after
Effective Date: December 1, 1999

Michael J. Hanson
Issued By: President & CEO

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
3rd Revised Sheet No. 2
Canceling 2nd Revised Sheet No. 2

CLASS OF SERVICE: General Gas Service — Rate No. 82
RATE DESIGNATION: Firm Sales

1. **Applicability**
This rate is available to non-residential customers whose maximum requirements for natural gas are not more than 200 therms per day. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements.

2. **Territory**
The area served with natural gas by the Company in South Dakota.

3. **Rates**

Monthly Charges:

Customer Charge per Meter:	$	7.00	(I)
Non-Gas Commodity Charge:			
First 400 therms, per therm	$	0.1305	(I)
Next 1,600 therms, per therm	$	0.0891	(I)
Over 2,000 therms, per therm	$	0.0541	
Standby Capacity Charge - December through March:	$	37.00	
Minimum Monthly Bill:	$	7.00	(I)

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. **Other Provisions**
The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: November 5, 1999
Service on and after
Effective Date: December 1, 1999

Michael J. Hanson
Issued By: President & CEO

SOUTH DAKOTA GAS RATE SCHEDULE

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
8th Revised Sheet No. 3.1
Canceling 7th Revised Sheet No. 3.1

CLASS OF SERVICE: Commercial and Industrial **Rate No. 84**
RATE DESIGNATION: Firm Sales Service

1. **Applicability**

This rate is available for firm gas volumes, on a contract basis, to commercial and industrial customers whose maximum requirements for natural gas are greater than 200 therms per day, and who may also require volumes of interruptible gas in excess of firm demand volumes for which they have contracted. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirement.

2. **Territory**

The area served with natural gas by the Company in South Dakota.

3. **Rates**

Customer may choose the rate option, and level of daily contract demand (never less than 50 therms), which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$ 80.00	$280.00	(I)
Non-Gas Commodity Charge, all use, per therm:	$0.0388	$0.0204	(I)

Demand Charge per therm of daily contract demand as shown on Sheet 9a.

Gas Demand Payment Elections

A. Annually - in advance, with 5% discount
B. Seasonally profiled

January & February	20% of annual charge per month
March & December	15% of annual charge per month
April & November	10% of annual charge per month
May & October	5% of annual charge per month
June through September	0% of annual charge per month

C. Monthly - 12 equal billings

In the absence of an appropriate election by customer Election "C" will be automatically assigned. Unless otherwise mutually agreed upon between the Company and customer all elections must be for a minimum period of twelve consecutive months.

Service on and after
Date Filed: November 5, 1999 Effective Date: December 1, 1999

Michael J. Hanson

NORTHWESTERN PUBLIC SERVICE — Section No. 3
HURON — 7th Revised Sheet No. 4.1
SOUTH DAKOTA — Canceling 6th Revised Sheet No. 4.1

CLASS OF SERVICE: Commercial and Industrial — **Rate No. 85**
RATE DESIGNATION: Interruptible Sales Service

1. Applicability

Gas service under this rate schedule is available on an interruptible basis to any customer for commercial and industrial purposes, whose maximum requirements for natural gas are greater than 200 therms per day, provided that the customer's premises are adjacent to the Company's mains and that the capability of the Company's system and the supply of gas available from its suppliers is in excess of the requirements of its existing customers. If no historical peak day usage is available, the name plate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirement.

2. Territory

The area served with natural gas by the Company in South Dakota.

3. Rates

Customer may choose the rate option which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$ 80.00	$280.00	(I)
Non-Gas Commodity Charge, all use, per therm:	$0.0388	$0.0204	(I)

Minimum Monthly Bill:
The Customer Charge.

Adjustment Clauses:

a. Adjustment Clause shall apply. (Sheet Nos. 9, 9a, 9b)
b. Tax Adjustment Clause shall apply. (Sheet No. 10)
c. BTU Adjustment Clause shall apply. (Sheet Nos. 12, 12a)
d. Manufactured Gas Plant Removal Cost Adjustment Clause shall apply. (Sheet No. 11)

4. Penalty Provision

If customer fails to comply with Company's request to curtail the use of gas, then all unauthorized gas so used shall be "Penalty Gas" and be paid by the Customer at a rate which is the greater of $3.00 per therm or the maximum penalty charges permitted to be made by the Company's upstream service providers for takes of natural gas in addition to the regular Commodity Charge for such gas. All costs collected will be credited to expense in PGA true-up filings.

NORTHWESTERN PUBLIC SERVICE
HURON
SOUTH DAKOTA

Section No. 3
8th Revised Sheet No. 6.1
Canceling 7th Revised Sheet No. 6.1

CLASS OF SERVICE: Gas Transportation Tariffs Rate No. 87
RATE DESIGNATION: Transportation Service

1. **Applicability and Character of Service**
This Transportation Service Tariff shall apply to gas purchased by Customer from a third-party supplier, or through an agency relationship with the Company, delivered to Company's system by an interstate pipeline, and received, transported, and delivered, on a firm basis, by Company to Customer's premises, when the Company and Customer have executed a Service Request Form.

2. **Availability**
This service is available to any Customer with facilities served by the Company in South Dakota who has Company installed telemetric equipment in place to monitor daily usage. Company shall have no obligation to provide gas supplies to customers that contract for this service without also contracting for Firm Supply Standby Service or other optional firm supply services that may be offered. In the event that a Customer seeks to purchase gas supplies from Company, such sales shall be at the sole discretion of Company.

3. **Rates**
Customer may choose the rate option which best fits the customer's needs.

Monthly Charges:	Option A	Option B	
Customer Charge per Meter:	$130.00	$330.00	(I)
Commodity Charge, all use, per therm:	$0.0388	$0.0204	(I)

Fuel Retention, a Customer or Group Customer, if applicable, shall have the option to choose either an indexed based or inkind method to apply retention, as provided in the Gas Transportation General Terms and Conditions in Section No. 5 of this tariff.

One-Time Charges:

Application Charge:	$50.00 with each request for service.
Telemetering:	Standard cost of telemetry, installation and hardware, including appropriate tax gross-up, shall be $2,100 per unit installed.

Minimum Monthly Bill:
The Customer Charge.

Date Filed: November 5, 1999
Service on and after
Effective Date: December 1, 1999

Michael J. Hanson
Issued By: President & CEO

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	DECISION AND ORDER APPROVING SETTLEMENT AGREEMENT NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission furt' er extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20-21, 1999, starting at 9:00 A.M. CDT, on October 20, 1999, in Room 413, State Capitol, Pierre, South Dakota. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a settlement agreement which increases the rates in the amount of $1,279,025. Staff requested that the Commission consider it on October 20, 1999. An issue related to the PGA was separated from the rate case issues and will be decided at a later date.

On October 20, 1999, the Commission convened and considered the settlement agreement along with the presentations of NWPS and Commission Staff and took the matter under advisement. On November 1, 1999, at a regularly scheduled meeting, the Commission approved the settlement agreement with an effective date of December 1, 1999.

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23. It is therefore

ORDERED, that the settlement agreement entered into between NWPS and Commission Staff on October 19, 1999, shall be approved and shall be incorporated by reference into this Decision and Order the same as if it had been set forth in its entirety herein.

Dated at Pierre, South Dakota, this 15th of November, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 11/16/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

JAMES A. BURG, Chairman

PAM NELSON, Commissioner

LASKA SCHOENFELDER, Commissioner

NorthWestern™
PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney
Telephone: 605-353-7504
Facsimile: 605-353-7519
rmolstad@northwestern.com

600 Market Street W
Huron, SD 57350-1500
Telephone 605-352-8411
Facsimile 605-353-7519
Internet www.northwestern.com

November 30, 1999

RECEIVED
NOV 30 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard
Executive Director
SD Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Docket No. NG99-002
Affiliate Contracts

Dear Mr. Bullard,

Pursuant to the settlement agreement reached in this matter, I am enclosing the following affiliate contracts:

- Management Services Agreements between NorthWestern Public Service and NorthWestern Services Corporation, NorthWestern Energy Corporation, NorCom Advanced Technologies, Inc.
- Aberdeen City-Gate Transportation Services Agreement between NorthWestern Public Service and NorthWestern Energy Corporation for the Nekota pipeline
- Contract to Manage Gas Supply between NorthWestern Public Service and Coast Energy Group
- NorthWestern Corporation Allocations to NorthWestern Public Service

We have included the NorthWestern Public Service and Coast Energy Group contract because we have a minority interest in Coast Energy Group's parent company, Cornerstone Propane.

In addition you will note that the management fee to be paid by NorthWestern Public Service to NorthWestern Services Corporation for the year 2000 is $1,500,000 instead of the $2,500,000 that was paid in 1999. The reason for the reduction in the management fee is that various services that had been provided by NorthWestern Services Corporation are now being done and paid for by NorthWestern. Services now being handled in-house and paid for by NorthWestern Public Service include marketing and customer service, customer associates and call-center management. NorthWestern Public Service will incur essentially the same expenses, but the expenses are now being incurred and paid directly by NorthWestern Public Service and not incurred through management fees paid to NorthWestern Services Corporation.

I believe with the filing of these contracts, NorthWestern has complied with the settlement agreement.

If you have any questions, please feel free to contact me.

Sincerely yours,

Russell C. Molstad

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker
Mike Hanson

MANAGEMENT SERVICES AGREEMENT

This MANAGEMENT SERVICES AGREEMENT ("Agreement") is made and entered this 29th day of November, 1999, to be effective January 1, 2000, by and between NORTHWESTERN PUBLIC SERVICE ("NPS), a division of NorthWestern Corporation, a Delaware corporation, and NORTHWESTERN SERVICES CORPORATION ("NSC"), a South Dakota corporation, for management services related to the operations of NPS' energy related and other diversified operations.

WHEREAS, NPS has a need for community relations services in connection with its energy and other diversified operations, including but not limited to:

Customer Relationships,
Community Relationships,
Load Building,
Energy Operations Support Services, and

WHEREAS, NSC has the required expertise and desires to provide said services to NPS.

NOW, THEREFORE, in consideration of these premises, the mutual covenants and agreements herein contained, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, NSC and NPS do hereby agree as follows:

I. SERVICES PROVIDED

A. NSC agrees to provide, and NPS agrees to pay for, community and customer relations services in connection with NPS' energy and other diversified operations, including but not limited to:

Customer Relationships,
Community Relationships,
Load Building,
Energy Operations Support Services.

B. The parties agree that the above-mentioned services are provided for NPS's existing South Dakota electric and gas operations, as well as Nebraska gas operations. Specific processes underlying these services are as follows:

1. Customer Relationship Services

- Meet with existing commercial and industrial utility customers to ensure the application of the appropriate rate, ascertain their satisfaction with NPS, identify any issues affecting their choice of energy supplier, and obtain information on their facility plans that might affect energy consumption or fuel choice.
- Meet with all new businesses moving into a NPS area to ensure the application of the appropriate rate, ascertain their satisfaction with NPS, identify any issues affecting their choice of energy supplier, and

obtain information on their facility plans that might affect energy consumption or fuel choice.

- Handle all communication and coordination with all NPS interruptible customers.
- Mediate a resolution for routine or lengthy customer problems referred to NSC by NPS.
- NSC will sponsor at least 12 events per year designed to improve relationships with NPS customers and others designated by NPS.

2. Community Relationship Services

- Establish and maintain meaningful relationships with each state legislator whose district encompasses an NPS operation, meeting periodically to explain issues of importance to NPS and its customers.
- For communities selected by NPS, establish and maintain meaningful relationships with mayors, city council members, and county commission members, attending meetings of those governing bodies as directed by NPS or when determined appropriate by NSC to monitor and/or participate in discussions of important issues.
- Participate, where appropriate, in community government, chamber of commerce, community task force, and other community organizations.

3. Load Building

- In communities designated by NPS, participate, work with, and support local community development corporation boards.
- Actively pursue new businesses for community development, load building, and job creation.

4. NPS Support Services

- Customer bill review.
- Research and field support.
- Assistance with management and board reports, strategic planning, new business development, acquisitions, and expansion projects as requested by NPS.

II. PRICING OF MANAGEMENT SERVICES PROVIDED

A. The parties agree that the pricing of the above services shall be based primarily upon NSC's direct costs plus allocated overheads plus margin for each contract year. Budgeted labor, and related benefit costs, will be allocated based on utilization of NSC employee labor profiles, updated on an annual basis. Other non-labor costs will be allocated to services based upon the labor distribution. Other non-allocated and non-budgeted costs that are attributable to services provided to NPS under this Agreement will be billed directly to NPS.

B. The fixed management services fees are shown on Appendix A to this Agreement.

C. Monthly installments for the fixed management services fees shall be due and payable by NPS to NSC by the 10th day of the month following the month service is provided. Direct charges will be billed after the month-end closing, and will be due at the same time the monthly installments are due.

III. LIMITATION OF LIABILITY AND INDEMNIFICATION

In performing the services hereunder (except to the extent such services are being performed by employees loaned to and under the supervision of NPS), NSC will exercise due care to assure that the services are performed in a workmanlike manner, meet the standards and specifications set forth in the applicable request with respect to such services, and comply with applicable standards of law and regulation. NSC shall and does hereby indemnify and agree to save harmless and defend NPS from the payment of any sum or sums of money on account of, or resulting from, claims or suits growing out of (i) injuries to or the death of any person, (ii) damage to or loss of any property and/or (iii) other damages in any way attributable to or arising out of the performance and prosecution of any project or work performed by or on behalf of NSC for others, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of, or breach of contract or willful conduct by, NSC or its employees, agents or subcontractors or any combination thereof.

IV. MISCELLANEOUS

A. This Agreement shall be binding upon the successors and assigns of the Parties, provided that neither NSC nor NPS shall be entitled to assign or subcontract out any of its obligations under this Agreement or under any request issued hereunder without the prior written approval of the other. This Agreement may not be modified or amended in any respect except in writing executed by the parties hereto. This Agreement shall be construed and enforced under and in accordance with the laws of the State of South Dakota (without regard to conflicts of law principles). No provision of this Agreement shall be deemed waived nor breach of this Agreement consented to unless such waiver or consent is set forth in writing and executed by the party hereto making such waiver or consent.

B. The provision of services by NSC pursuant to this Agreement shall be subject to any limitation contained in any authorizations, rules or regulations of those governmental agencies, if any, having jurisdiction over the parties, or such provision of services.

V. CONFIDENTIAL INFORMATION

A. Confidential Information shall include all market information concerning the businesses conducted by either NSC or NPS, and any other information designated as confidential by either party.

B . Confidential Information shall not include:

1. Information lawfully known to NSC prior to the performance of such services other than through other work with or for NPS; or

2. Information that is publicly disclosed through no act of NSC or any of NSC's employees, either prior or subsequent to NPS's disclosures of such information to NSC.

C. During the term of the Agreement and thereafter, except as NPS may authorize in writing, the NSC shall and shall cause its employees to:

1. Treat and cause to be treated as confidential all Confidential Information;

2. Grant access to Confidential Information only to NSC's employees performing services pursuant to this Agreement and NSC's supervisory personnel needing access to Confidential Information;

3. Use Confidential Information only in connection with the performance of services pursuant to this Agreement;

4. Make copies of any tangible embodiment of Confidential Information only as necessary for the performance of such services;

5. Remove any tangible embodiment of Confidential Information from the premises of NPS only with the express permission of NPS; and

6. Return any or all tangible embodiments of Confidential Information to NPS promptly following the request of NPS, and in any event upon completion of work pursuant to the Agreement.

D. Notwithstanding the foregoing, either party may disclose Confidential Information to the extent that disclosure is required by a court or other governmental agency of competent jurisdiction, provided that the party shall provide notice to the other of the request for such disclosure promptly upon receiving such notice.

VI. TERM

The initial term of this Agreement shall be for a period of one (1) year from January 1, 2000 through December 31, 2000, with automatic one (1) year rollovers unless ninety (90) days prior written notice of intent to terminate the Agreement is served by either party on the other party.

Agreed to by the parties the 29th day of November 1999.

NorthWestern Public Service
a division of NorthWestern Corporation

By: _____
President & CEO

Attest:
_____
Secretary

NorthWestern Services Corporation

By: _____
President & CEO

Attest:

_____

Agreed to by the parties the 29th day of November 1999.

NorthWestern Public Service
a division of NorthWestern Corporation

By: _____
President & CEO

Attest:

_____

NorthWestern Services Corporation

By: _____
President & CEO

Attest:

APPENDIX A
MANAGEMENT SERVICES AGREEMENT
Between
NorthWestern Public Service, a division of NorthWestern Corporation and
NorthWestern Services Corporation

Original

	Annual Fee	Monthly Installment
Fees for Services – Calendar Year 2000	$1,500,000	$125,000

MANAGEMENT SERVICES AGREEMENT

This MANAGEMENT SERVICES AGREEMENT ("Agreement") is made and entered this 23rd day of November, 1999, to be effective January 1, 2000, by and between NORTHWESTERN PUBLIC SERVICE, a division of NorthWestern Corporation ("NPS"), a Delaware corporation, and NORTHWESTERN ENERGY CORPORATION ("NEC"), a South Dakota corporation for management services related to the operations of NPS' energy related and other diversified operations.

WHEREAS, NPS has a need for management services in connection with its energy and other diversified operations, including but not limited to:

Regulatory Services,
Rate and Tariff Administration Services,
Energy Procurement and Accounting Services,
Energy Operations Support Services, and

WHEREAS, NEC has the required expertise and desires to provide said services to NPS.

NOW, THEREFORE, in consideration of these premises, the mutual covenants and agreements herein contained, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, NEC and NPS do hereby agree as follows:

I. SERVICES PROVIDED

A. NEC agrees to provide, and NPS agrees to pay for, management services in connection with NPS' energy and other diversified operations, including but not limited to:

Regulatory Services,
Rate and Tariff Administration Services,
Energy Procurement and Accounting Services,
Energy Operations Support Services.

B. The parties agree that the above-mentioned services are provided for existing South Dakota electric and gas operations, as well as Nebraska gas operations. Specific processes underlying these services are as follows:

1. *Regulatory Services* include involvement in all South Dakota and Nebraska natural gas and electric rate proceedings, utility return analysis, heating degree day tracking, 10-year electric plan filings, EIA filings, and other required regulatory filings.

2. *Rate and Tariff Administration Services* include filings and accounting for PGA true-ups, electric fuel true-up, Btu content, ad valorem tax true-ups, delivered cost of energy true-up, MGP cleanup cost tracker, gas lost & unaccounted for tracking, WAPA bill crediting program, FERC electric transmission tariff, MAPP subcommittees and other electric tariff issues.

3. *Energy Procurement and Accounting Services* include gas supply planning, forecasting, nominations, balancing, accounting and reporting, including participation and monitoring of FERC regulated pipeline rate proceedings involving KN Interstate, Northern Natural Gas and Northern Border,

4. *Energy Operations Support Services* include utility service billing support, including electric sales for resale, gas transportation billings, and customer bill review, research and field support. In addition, additional processes include assistance in management and board reports, strategic planning, potential acquisition review, new business development and expansion projects, gas and electric sales and cost budget preparation, and administration of Nebraska gas agency sales.

II. PRICING OF MANAGEMENT SERVICES PROVIDED

A. The parties agree that the pricing of the above services shall be based primarily upon an allocation of NEC's budgeted costs for each contract year. Budgeted labor, and related benefit costs, will be allocated based on utilization of NEC employee labor profiles, updated on an annual basis. Other non-labor costs will be allocated to services based upon the labor distribution. For basis of cost allocation under this Agreement, only fifty percent of NEC's budgeted short-term incentive compensation will be included in costs. Costs paid by NEC for outside regulatory costs relating to the Northern Distributor Group (South Dakota gas) and the annual FERC ACA charges (South Dakota electric) have not been included in costs to be allocated as these costs will be billed directly to NPS when incurred. Other non-allocated and non-budgeted costs that are attributable to services provided NPS under this Agreement, such as rate case related expenses, will be billed directly to NPS.

B. The fixed management services fees are shown on Appendix A to this Agreement.

C. Monthly installments for the fixed management services fees shall be due and payable by NPS to NEC by the 10th day of the month following the month service is provided. Direct charges will be billed after the month-end closing, and will be due at the same time the monthly installments are due.

III. LIMITATION OF LIABILITY AND INDEMNIFICATION

In performing the services hereunder (except to the extent such services are being performed by employees loaned to and under the supervision of NPS), NEC will exercise due care to assure that the services are performed in a workmanlike manner, meet the standards and specifications set forth in the applicable request with respect to such services, and comply with applicable standards of law and regulation. Each Company shall and does hereby indemnify and agree to save harmless and defend the other Company from the payment of any sum or sums of money on account of, or resulting from, claims or suits growing out of (i) injuries to or the death of any person, (ii) damage to or loss of any property and/or (iii) other damages in any way attributable to or

arising out of the performance and prosecution of any project or work performed by or on behalf of the Company for others, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of, or breach of contract or willful conduct by, the Company or its employees, agents or subcontractors or any combination thereof. Further, the Company shall and does hereby indemnify and agree to save harmless and defend the other Company (a) from any and all liens, garnishments, attachments, claims, suits, costs, attorneys' fees, cost of investigation and of defense resulting from, incurred in connection with, or relating to any such claims, (b) from the payment of any such sum or sums of money, and (c) from the payment of any penalties, fines, damages, suits or claims (and any liens or attachments asserted in connection therewith) arising out of (i) any alleged or actual violation of law, court order, or governmental agency rule or regulation committed by or existing with respect to the Company or its employees, agents or subcontractors (except the Company when not performing services hereunder), or (ii) any alleged or actual breaches of contract by the Company, or (iii) any claims made by or on account of any employee, agent or subcontractor (except the Company when not performing services hereunder or any employee or agent of the Company where such claim does not arise specifically in connection with the performance of services hereunder) of the other Company, or (iv) services or labor performed, materials, provisions or supplies furnished or which have been purchased or contracted for by or on behalf of the Company, its employees, agents or subcontractors (except the Company when not performing services hereunder).

IV. CONFIDENTIAL INFORMATION

A. Confidential Information shall include all market information concerning the businesses conducted by either Company, and any other information designated as confidential by either Company.

B. Confidential Information shall not include:

1. Information lawfully known to the Company prior to the performance of such services other than through other work with or for the other Company; or

2. Information that is publicly disclosed through no act of the Company or any of the Company's employees, either prior or subsequent to the other Company's disclosures of such information to the Company.

C. During the term of the Agreement and thereafter, except as the Company may authorize in writing, the other Company shall and shall cause its employees to:

1. Treat and cause to be treated as confidential all Confidential Information;

2. Grant access to Confidential Information only to NEC's employees performing services pursuant to this Agreement and NEC's supervisory personnel needing access to Confidential Information;

3. Use Confidential Information only in connection with the performance of services pursuant to this Agreement;

4. Make copies of any tangible embodiment of Confidential Information only as necessary for the performance of such services;

5. Remove any tangible embodiment of Confidential Information from the premises of the other Company only with the express permission of the other Company; and

6. Return any or all tangible embodiments of Confidential Information to the other Company promptly following the request of that Company, and in any event upon completion of work pursuant to the Agreement.

D. Notwithstanding the foregoing, either Company may disclose Confidential Information to the extent that disclosure is required by a court or other governmental agency of competent jurisdiction, provided that that Company shall provide notice to the other Company of the request for such disclosure promptly upon receiving such notice.

V. TERM

The initial term of this Agreement shall be for a period of one (1) year from January 1, 2000 through December 31, 2000, with automatic one (1) year rollovers unless ninety (90) days prior written notice of intent to terminate the Agreement is served by either party on the other party.

Agreed to by the parties the 29th day of November 1999.

NorthWestern Public Service
a division of NorthWestern Corporation

By: _____
President & CEO

Attest:
_____
Secretary

NorthWestern Energy Corporation

By: _____
President & CEO

Attest:
_____
Secretary

APPENDIX A
SERVICES AGREEMENT
Between
NorthWestern Public Service, a division of NorthWestern Corporation and
NorthWestern Energy Corporation

Original

Fees for Services – Calendar Year 2000

	Annual Fee	Monthly Installment
South Dakota Electric Operations	$428,382	$35,699
South Dakota Gas Operations	$398,572	$33,214
Nebraska Gas Operations	$277,493	
Less Cost Collected in Separate Gas Supply Management Agreement	($208,844)	$ 5,721
Total Monthly Allocated Fee		$74,634

MANAGEMENT SERVICES AGREEMENT

This MANAGEMENT SERVICES AGREEMENT ("Agreement") is made and entered this 29th day of November, 1999, to be effective January 1, 2000, by and between NORTHWESTERN PUBLIC SERVICE ("NPS), a division of NorthWestern Corporation, a Delaware corporation, and NORCOM ADVANCED TECHNOLOGIES, INC. ("NorCom"), a South Dakota corporation, for management services related to administrative, marketing, technical and other services.

WITNESSETH:

WHEREAS, NPS has a need for certain managerial, administrative, marketing, technical and other services, and certain resources; and

WHEREAS, the Parties desire that NorCom provide such services and resources to NPS subject to the terms and conditions described herein;

NOW, THEREFORE, in consideration of the premises, the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiencies of which is hereby acknowledged, NorCom and NPS do hereby agree as follows:

I. SERVICES PROVIDED

NorCom will furnish to NPS, upon the terms and conditions hereinafter set forth herein, such services, at such times and in such manner as described in detail in the attached Exhibit A.

II. PRICING OF SERVICES PROVIDED

The parties agree that the pricing of the services set forth on Exhibit A shall be as set forth in Exhibit A.

III. LIMITATION OF LIABILITY AND INDEMNIFICATION

In performing the services hereunder (except to the extent such services are being performed by employees loaned to and under the supervision of NPS), NorCom will exercise due care to assure that the services are performed in a workmanlike manner, meet the standards and specifications set forth in the applicable request with respect to such services, and comply with applicable standards of law and regulation. Each Company shall and does hereby indemnify and agree to save harmless and defend the other Company from the payment of any sum or sums of money on account of, or resulting from, claims or suits growing out of (i) injuries to or the death of any person, (ii) damage to or loss of any property and/or (iii) other damages in any way attributable to or arising out of the performance and prosecution of any project or work performed by or on behalf of the Company for others, whether or not the same results or allegedly results from the claimed or actual negligence or breach of warranty of, or breach of contract or willful conduct by, the Company or its employees, agents or subcontractors or any combination thereof.

IV. MISCELLANEOUS

A. This Agreement shall be binding upon the successors and assigns of the Parties, provided that neither Company shall be entitled to assign or subcontract out any of its obligations under this Agreement or under any request issued hereunder without the prior written approval of the other Company. This Agreement may not be modified or amended in any respect except in writing executed by the parties hereto. This Agreement shall be construed and enforced under and in accordance with the laws of the State of South Dakota (without regard to conflicts of law principles). No provision of this Agreement shall be deemed waived nor breach of this Agreement consented to unless such waiver or consent is set forth in writing and executed by the party hereto making such waiver or consent.

B. The provision of services by either Company pursuant to this Agreement shall be subject to any limitation contained in any authorizations, rules or regulations of those governmental agencies, if any, having jurisdiction over the Parties, or such provision of services.

C. Either Company may terminate this Agreement upon thirty (30) days' prior written notice to the other Company.

V. CONFIDENTIAL INFORMATION

A. Confidential Information shall include all market information concerning the businesses conducted by either Company, and any other information designated as confidential by either Company.

B. Confidential Information shall not include:

1. Information lawfully known to the Company prior to the performance of such services other than through other work with or for the other Company; or

2. Information that is publicly disclosed through no act of the Company or any of the Company's employees, either prior or subsequent to the other Company's disclosures of such information to the Company.

C. During the term of the Agreement and thereafter, except as the Company may authorize in writing, the other Company shall and shall cause its employees to:

1. Treat and cause to be treated as confidential all Confidential Information;

2. Grant access to Confidential Information only to NorCom's employees performing services pursuant to this Agreement and NorCom's supervisory personnel needing access to Confidential Information;

3. Use Confidential Information only in connection with the performance of services pursuant to this Agreement;

4. Make copies of any tangible embodiment of Confidential Information only as necessary for the performance of such services;

5. Remove any tangible embodiment of Confidential Information from the premises of the other Company only with the express permission of the other Company; and

6. Return any or all tangible embodiments of Confidential Information to the other Company promptly following the request of that Company, and in any event upon completion of work pursuant to the Agreement.

D. Notwithstanding the foregoing, either Company may disclose Confidential Information to the extent that disclosure is required by a court or other governmental agency of competent jurisdiction, provided that that Company shall provide notice to the other Company of the request for such disclosure promptly upon receiving such notice.

VI. TERM

The initial term of this Agreement shall be for a period of one year from January 1, 2000 to December 31, 2000, with automatic one (1) year rollovers unless ninety (90) days prior written notice of intent to terminate the Agreement is served by either party on the other party.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed in their respective corporate names by their respective Presidents or one of their respective Vice Presidents as of the day and year first above written.

Agreed to by the parties this 29th day of November, 1999.

NorthWestern Public Service
a division of NorthWestern Corporation

By: _____
President & CEO

Attest: _____
Secretary

NorCom Advanced Technologies, Inc.

By: _____
President & CEO

Attest: _____
Secretary

EXHIBIT A
to
Management Services Agreement
dated November 29, 1999

1. Services provided by NorCom Advanced Technologies, Inc. to Northwestern Public Service:

a. Description of Services:

Telephone Consulting
- Contract negotiation
- Planning
- Long distance
- Data telemetry
- PBX Networking
- Billing verification and approval

SCADA Consulting
- Gas system
- Electric system
- MAPP data integration

Customer Service Center Consulting
- Planning
- Integration and installation
- Equipment selection and purchasing

IT Consulting
- Planning
- Internet access
- Data (ISDN, Frame Relay, etc.)
- Automated meter reading
- Wireless Data

Radio Services
- VHF voice radio services
- FCC license maintenance
- Repair and maintenance of radio equipment
- Installation and repair of cellular equipment
- Microwave data telemetry services

Telephone System Support (Huron, Aberdeen, Mitchell, Yankton)

- System administration
- Hardware maintenance labor
- Network monitoring
- Cellular telephone administration

SCADA System Support

- Primary Support for Gas SCADA System
- Secondary (Backup) Support for Electric SCADA System

b. Expanded and Additional Services

Any expansion of the services identified in this agreement and any additional services provided under this agreement will be billed to NPS at a rate of 20% per year of the additional capital costs required to provide these expanded and additional services.

c. Consideration:

	2000 Budget	2000 Monthly
Radio System Fees	279,756	23,313
Microwave and MAS Fees	244,332	20,361
Telephone Service Mgmt. Fees	92,304	7,692
Electric & Gas SCADA Fees	54,300	4,525
Fiber Optic System Support Fees	27,144	2,262
CSC Support Fees	27,144	2,262
Tower Lease / Rentals	18,000	1,500
Communications Mgmt. Fees	75,996	6,333
IT Support (Consulting) Fees	6792	566
Cellular Phone Management Fees	2148	179
	827,916	68,993

The above-described consideration represents direct costs associated with the services provided to NPS by NorCom. In addition, any outside services that may be required from time to time will be either billed directly to NPS or billed to NPS by NorCom if paid by NorCom.

Savings Split

In addition to the stated compensation, NorCom would receive 25% of any savings generated by the negotiation or renegotiation of any contract on the behalf of NPS, any savings resulting from the installation of new technology or equipment, and any other savings that are received by NPS as a direct result of

the actions of NorCom. In the event the savings occurs due to a new or renegotiated contract, the savings will be based on the term of the negotiated contract and will be billed as a single present value payment upon execution of the contract. Savings occurring due to the installation of new equipment, shall recognize the annualized cost associated with installation required to realize savings. The term will be based on the usable life of the equipment (not to exceed 5 years), and be billed as a single present value payment at the time the project is operational.

ABERDEEN CITY-GATE
TRANSPORTATION SERVICES AGREEMENT

This ABERDEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT ("Agreement") is made and entered this 22nd day of November, 1999, to be effective December 1, 1999, by and between NORTHWESTERN ENERGY CORPORATION, a South Dakota corporation, herein referred to as "Seller," and NORTHWESTERN PUBLIC SERVICE, a division of NorthWestern Corporation, a Delaware corporation, herein referred to as "Buyer."

WHEREAS, Seller has purchased natural gas transportation capacity on the Warner pipeline from Nekota Resources, Inc. ("Nekota"), with such pipeline extending from an interconnection on the Northern Border Pipeline Company's interstate natural gas pipeline south of Aberdeen, South Dakota to the Aberdeen city-gate of Buyer; and

WHEREAS, Buyer has the desire to continue to have competitively priced retail natural gas rates in South Dakota and to obtain the services of Seller to deliver competitively priced upstream pipeline capacity for delivery of natural gas to Buyer's distribution system in Aberdeen;

NOW, THEREFORE, in consideration of these premises, the mutual covenants and agreements herein contained, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, Seller and Buyer do hereby agree as follows:

I. QUANTITY

A. Seller agrees to receive from Buyer for transportation on a firm basis quantities of natural gas tendered by Buyer on any day at the Primary Receipt Point(s), and Seller agrees to transport and deliver to Buyer at the Delivery Point(s) up to the full capacity of the Warner pipeline in accordance with the terms and conditions set forth in this Agreement.

B. The Firm Daily Quantity ("FDQ") shall be 15,000 Dekatherms per day at the Delivery Point(s), subject to any adjustment allowed under this Agreement.

C. Subject to and conditioned upon gas being delivered to Seller by Buyer, Seller will exercise due diligence and good faith to provide additional transportation service (i.e. a quantity of gas in excess of the FDQ) to Buyer on a reasonable efforts basis up to the maximum capacity available on the Warner pipeline at the rate set forth in Article II. A.

II. PRICE

Buyer shall remit to Seller each month a Monthly Demand Charge equal to the higher of $3.20 times the total FDQ or fifty-five percent (55%) of Buyer's

weighted average monthly Northern Natural Gas Company TF (Market Firm) capacity costs, at maximum FERC approved base rates. The determination of the calculation of such weighted average monthly rate, to be effective December 1, 1999, is shown on Appendix B to this Agreement. If Buyer exceeds the FDQ on any given day, the transportation overrun Dekatherms will be billed at the then applicable 100% load factor demand rate for those days in which overrun volumes are transported.

III. DELIVERY POINTS

The Delivery Point(s) shall be the points of interconnection between the facilities of the Warner pipeline of Nekota and Buyer at Buyer's town border station in Aberdeen, South Dakota.

IV. TERM

The initial term of this Agreement shall be ten (10) years, commencing December 1, 1999, and ending on November 30, 2009, subject to the other provisions of this Agreement, and subject to Buyer's right to extend the Agreement for an additional term of ten (10) years, by giving six (6) months' notice to Seller prior to the end of the initial term.

V. GENERAL TERMS AND CONDITIONS

The sale of transportation capacity hereunder shall be subject to the General Terms and Conditions attached hereto as Appendix A and made a part hereof. In the event of a conflict between the foregoing provisions of this Agreement and the provisions of Appendix A, the provisions of this Agreement shall govern.

IN WITNESS WHEREOF, each of said parties has caused this Agreement to be executed in its corporate name and attested by its officers thereto duly authorized upon the date written above.

SELLER: NORTHWESTERN ENERGY CORPORATION

By: _____
Its: _____

Attest: _____
Title: Secretary

BUYER: NORTHWESTERN PUBLIC SERVICE
a division of NorthWestern Corporation

By: _____
Its: _____

Attest: _____
Title: Secretary

APPENDIX A
ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT

GENERAL TERMS AND CONDITIONS

ARTICLE I
DEFINITIONS

A. For the purpose of this Agreement the following definitions shall apply:

1. "BTU" (British Thermal Unit") is the amount of energy required to increase the temperature of one (1) pound of water one (1) degree Fahrenheit at fifty-nine (59) degrees Fahrenheit.

2. "Contract Year" is a period of twelve (12) consecutive Months commencing and ending at 9:00 o'clock a.m. Central Clock Time on December 1 unless otherwise agreed.

3. "Cubic Foot of Gas" is the amount of gas necessary to fill one cubic foot of space when the gas is at a temperature of sixty (60) degrees Fahrenheit and under an absolute pressure of fourteen and seventy-three hundredths (14.73) pounds per square inch.

4. "Day" is a period of twenty-four (24) consecutive hours beginning and ending at nine (9) o'clock a.m. Central Clock Time ("CCT") or at such other time as Buyer and Seller may agree upon.

5. "Delivery Point(s)" is the point or points designated in this Agreement where Seller's supply is sold and purchased hereunder and delivered to Buyer. Title to and possession of Seller's supply passes from Seller to Buyer at such point(s).

6. "Gas" or "Natural Gas" is any mixture of hydrocarbons or of hydrocarbons and non-combustible gas, in a gaseous state, consisting essentially of methane; or all merchantable gases that conform to the quality specifications of the Transporting Pipeline.

7. "Total Dry Heating Value" is the number of Btus produced by complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of 1 cubic foot at a temperature of 60 degrees Fahrenheit on a water-free basis and at a pressure of 14.73 p.s.i.a. with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has condensed to the liquid state.

8. "Dekatherms" is one million (1,000,000) British thermal units.

9. "Month" is a period beginning at 9:00 o'clock a.m. Central Clock Time, or at such other time as the parties have agreed upon, on the first Day of the calendar Month and ending at the same time on the first Day of the next calendar Month.

10. "Monthly Billing Period" is the calendar Month.

11. "Party" is Buyer or Seller.

12. "Parties" is Buyer or Seller.

13. "PSI" is the pressure measured in pounds per square inch.

14. "p.s.i.a." is pound per square inch absolute.

15. "p.s.i.g." is pound per square inch gauge.

16. "Quantity" when used to refer to a quantity of gas shall mean the Total Energy Content.

17. "Total Energy Content" is that amount determined by multiplying the total dry heating value by the volume of gas in cubic feet.

18. "Transporting Pipeline" is any pipeline providing transportation or storage service prior to Buyer's distribution system.

ARTICLE II
WARRANTY AND TITLE

A. Seller warrants, at the time of delivery, Seller's title to, and its rights to sell, the gas delivered hereunder, and warrants that such gas is free from liens, encumbrances, and adverse claims. Seller agrees to indemnify Buyer against any direct loss, damage, or expense which Buyer may sustain from a claim involving gas sold or delivered hereunder prior to delivery into the Buyer's distribution system. Buyer agrees to indemnify Seller against any direct loss, damage or expense which Seller may sustain from a claim involving gas sold or delivered hereunder after delivery into the Buyer's distribution system. Neither party shall be liable to the other for indirect, consequential, or special damages related to this Agreement.

ARTICLE III
TAXES

A. Seller shall pay or cause to be paid all taxes lawfully levied on Seller applicable to the gas sold hereunder prior to delivery into the Buyer's distribution system. Buyer shall pay or cause to be paid all taxes lawfully levied on Buyer applicable to the gas sold hereunder after delivery into the Buyer's distribution system. Absent Seller's receipt from Buyer of an appropriate sales tax exemption certificate, Buyer shall be obligated to remit to Seller, and Seller shall be entitled to collect from Buyer, any applicable state sales tax levied on the sale of gas under this Agreement.

ARTICLE IV
QUALITY & MEASUREMENT

A. All gas delivered hereunder shall meet the quality specifications of the Transporting Pipeline and shall be measured by and in accordance with the measurement requirements of the Transporting Pipeline, unless the gas delivered by Seller hereunder was nevertheless accepted by the Transporting Pipeline and the gas that was actually delivered to Buyer's TBS met the written quality specifications set forth in the Transportation Pipeline's tariff.

ARTICLE V
IMBALANCE PENALTIES

A. The parties recognize that Buyer will be liable for any reasonable charges and penalties imposed by the Transporting Pipeline for imbalances or variances in deliveries. Seller agrees to act in good faith and with due diligence to avoid any such charges or penalties, and to cooperate in a timely fashion to adjust gas forecasts, nominations and/or deliveries as necessary to bring deliveries and receipts into balance to the extent that penalties are avoided or minimized as much as possible.

ARTICLE VI
BILLING AND PAYMENT

A. Seller shall use reasonable efforts to render invoices on or before the fifteenth (15th) Day of each Month for the Monthly Demand Charge applicable to the current Month. Invoices shall also reflect any applicable adjustments from prior Months. When information necessary for billing purposes is in the control of Buyer, such information relating to the prior Month shall be delivered to Seller by Buyer on or before the fifth (5) business Day of each Month.

B. Buyer shall pay Seller by wire transfer to the place and account designated by Seller in the Agreement:

1. On or before the twenty-fifth (25) Day of each Month all charges reflected on the invoice rendered by Seller in the current Month pursuant to Paragraph A of this Article; provided, however, that payment shall never be due until ten (10) Days after the receipt of the Seller's invoice; and

2. Any adjustments or additional payments shall be paid with the next following month's invoice.

C. Any invoiced amount due Seller under this Agreement not paid when due shall bear interest calculated at the daily equivalent of the Prime Rate plus two (2%) percent per annum. "Prime Rate" shall mean the per annum rate of interest for established commercial customers published from time to time by Norwest Bank South Dakota, N.A.

D. Any payments received from Buyer shall first be applied to any accrued interest due, then to the principal portion of any overdue charges, and lastly to the principal portion of any charges currently due.

E. Seller and Buyer shall each have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge or computation made under or pursuant to any of the provisions hereof.

ARTICLE VII
FORCE MAJEURE

A. The term "force majeure" shall mean acts of God; earthquakes, landslides, lightning, fires, storms, floods, washouts, freezing of wells or pipelines, explosions, rupture of lines of pipe, breakage of or accident to machinery, wells, gathering lines, pipelines, compressors or plants or any other interdicting, physical event; strikes, lockouts, or other industrial disturbances; or wars, riots, civil disturbances, or insurrections; regulation or order of a governmental agency limiting access to gas supply; partial or entire failure of gas supply over which Seller has not control; failure or inability of Transporting Pipeline(s) to transport gas; inclement weather that necessitates extraordinary measures and expense to construct facilities and/or maintain operations; acts of governmental authorities having jurisdiction (including, but not limited to, federal, state, or municipal entities) which render either party unable to legally carry out their obligations, or which significantly impact a party's ability to meet its commitments under this Agreement, excepting any governmental acts made at the request of the party

claiming force majeure; or any other cause or causes beyond reasonable control of the party, whether of the kind enumerated or otherwise; provided, however, that none of the foregoing shall constitute an event of force majeure unless it is not reasonably within the control of the party claiming the occurrence thereof. Neither party shall be entitled to claim economic force majeure with respect to any agreed upon price for the sale or purchase of any services or supply under this Agreement.

B. If either Seller or Buyer is rendered unable by the occurrence of an event of force majeure to carry out in whole or in part its obligations hereunder, the obligations to make demand charge payments and payments for services performed or supplies actually delivered, shall be suspended during the continuance and to the extent of any inability so caused but for no longer period, and such cause shall, so far as possible, be remedied with all reasonable dispatch. An event of force majeure shall not, however, relieve a party of liability in the event or its concurring negligence or for any period during which it fails to use reasonable diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch; nor shall the event relieve a party of liability under any circumstances unless the party gives notice and full particulars of the same in writing or by facsimile to the other party as soon as possible after the occurrence. The foregoing notwithstanding, nothing herein shall require either party to settle a strike against its will.

C. This Agreement shall not be terminated by reason of any suspension of obligations hereunder due to the occurrence of an event of force majeure.

ARTICLE VIII
ASSIGNMENT

A. Seller may assign, or grant a security interest in, any or all its rights to or in respect of payments made or to be made (or due or to become due) under this Agreement. This Agreement may not otherwise be assigned by either party without the written consent of the other party, which consent shall not be unreasonably withheld. Each successor to Seller and Buyer shall be bound by this Agreement.

ARTICLE IX
MISCELLANEOUS

A. Waiver. No waiver by Buyer or Seller of anyone or more defaults by the other in its performance under any provision hereof shall operate or be constructed as a waiver of any future default or defaults, whether of a like or different character. No delay, short of the statutory period of limitation, in asserting or enforcing any right hereunder shall be deemed a waiver of or limitation on such right.

B. Amendment. Any change in the provisions of this Agreement made subsequent to the date of execution hereof shall not be binding unless made by executed, written amendment, and no course of dealing or course of performance between the parties, or trade usage, shall be considered in determining the meaning and intent of the terms and conditions stated herein.

C. Third-Party Beneficiaries. Except as a result of an assignment permitted herein, this Agreement shall not give rise to any rights in any person not a signatory party hereto. In particular, no person shall be entitled to claim the status of a third-party beneficiary with respect to or on account of any provision of this Agreement.

D. Headings. The descriptive headings for the articles and sections contained in this Agreement are for convenience only and shall not be considered to affect the meaning or interpretation of the provisions herein.

E. Notices and Communications. All notices or communications required by this Agreement to be given to a party in writing shall be addressed as follows:

If to Buyer:

NorthWestern Public Service, a division of NorthWestern Corporation
600 Market ST. W
Huron, SD 57350-1500
Attention: Executive Vice President
Phone: (605) 353-7502 Facsimile: (605) 353-7519

If to Seller

NorthWestern Energy Corporation
33 Third Street SE
P. O. Box 1318
Huron, SD 57350-1318
Attention: Executive Vice President
Phone: (605) 353-8235 Facsimile: (605) 353-8216

All payments by Buyer and Seller shall be wire transferred to:

Wire transfer information for Seller:

Norwest Bank, Huron Office, N.A.
ABA #
Acct: Northwestern Energy Corporation
Acct # 1800015237

Any party may change the address to which notices, communications, or payments are to be sent by giving the other party written notice of such change in the manner provided for by this section. Receipt or notices, communications or invoices shall be deemed effective when received if sent by U.S. mail or date faxed or date placed with overnight delivery service unless otherwise provided for in this Agreement.

F. Applicable law. The parties' rights and obligations hereunder shall be interpreted in accordance with the laws of the State of South Dakota, except for any doctrine or provision thereof that would direct the application of the laws of another state. Any legal action under this Agreement must be brought before a court in the State of South Dakota.

APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
NorthWestern Public Service, a division of NorthWestern Corporation and
NorthWestern Energy Corporation

Original

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	NorthWestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective December 1, 1999				
TF -12 Base	$4.4980	10,488	7	$27,518.76
	$8.0960	10,488	5	$35,379.52
TF -12 Variable	$4.4980	21,414	7	$56,186.77
	$10.9750	21,414	5	$97,924.44
TFX-7	$4.4980	4,590	2	$3,440.97
	$11.9940	4,590	5	$22,938.53
TF-5	$11.9940	20,313	5	$101,514.22
	$6.0717	56,805		$344,903.21
55% of Weighted Rate per MDQ	$3.3394			
Higher of Above Rate or $3.2000	$3.3394			
Overrun Rate (100% LF)	$0.1098			

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CONTRACT TO MANAGE GAS SUPPLY

Coast Energy Group ("Coast"), a Division of Cornerstone Propane L.P., and Northwestern Public Service ("Northwestern"), a Division of Northwestern Corporation, hereby agree to the following terms and conditions for the management of Northwestern's gas supply by Coast, effective August 1, 1999.

1. Coast will prudently arrange and manage all of Northwestern's firm natural gas supply for its South Dakota retail distribution operations, arranging all supply and transportation services upstream of the town border stations at the communities served by Northwestern (Northwestern's Zone ABC POI #3096), with specific responsibility for the following:

   a. Coast shall make and charge on behalf of Northwestern all nominations for daily deliveries to and from the Receipt Point(s) to the applicable city gate. (Zone ABC POI #3096)

   b. Coast shall prudently manage all of Northwestern's transportation, supply and storage agreements relating to natural gas service and utilize or release capacity when not required or requested by Northwestern.

   c. Coast shall bear exclusive and ultimate financial responsibility, and shall pay to any pipeline or reimburse Northwestern if Northwestern is required to pay cash-out costs, or similar costs assessed by the pipeline as a result of (I) an overdelivery of gas for deliveries into a transportation agreement or (II) an underdelivery of gas for deliveries into a transportation agreement. Notwithstanding the foregoing, Coast will bear no financial responsibility for the aforementioned charges to the extent Coast was following Northwestern's instructions or relying on information provided to Coast by Northwestern. Coast will use reasonable efforts to minimize pipeline penalties.

   d. Coast will provide Northwestern with periodic (at least monthly) management reports detailing all activities undertaken for Northwestern, and the status of Northwestern storage transportation and supply agreements. Quarterly planning meetings will be held to develop ongoing strategy to minimize costs. Coast will monitor federal regulatory issues that could affect Northwestern's account and provide timely information as well as long range strategic consultation.

   e. Coast shall provide to Northwestern various risk management services and marketing assistance including Weekly Product Pricing Update for Agency Program. Products offered weekly include:

      - Fixed price baseload
      - Cap price for fixed volume
      - Fixed price for weather sensitive volume
      - Seasonal storage programs
      - Market sensitive pricing

2. Northwestern will assist Coast in its management responsibilities by nominating, on a daily basis, quantities of natural gas necessary to meet Northwestern's system gas needs. Such nominating may be made orally, electronically, or in writing, but all oral nominations will be

followed by a written confirmation. Northwestern may, at any time, change the nominated quantity, provided sufficient notice of such change is provided to obtain pipeline acceptance of the change.

3. The Maximum Daily Quantity ("MDQ") for Northwestern's system in South Dakota is 52,215 MMBtu. Northwestern may, based on weather forecasts, or other relevant data nominate any quantity on a daily basis. For all volumes in excess of Northwestern's Firm MDQ, Coast shall use the most economical and reliable means to meet Northwestern's full requirements. Northwestern shall notify Coast orally and in writing of the nomination quantities. Options available to Northwestern may or shall be secondary released capacity, interruptible transportation, firm overrun and/or peak shaving. Northwestern shall have the right at any time to change the nominated quantity, provided Northwestern shall provide notice of such change pursuant to the applicable pipeline nomination deadline and the applicable pipeline accepts such nomination change. Coast shall have employees available at all times to receive such changes from Northwestern and effectuate the changes. The contact person should be capable (and prepared) to accept scheduling changes, respond to critical notices from the pipeline, and to address any other concerns Northwestern might have regarding business transactions between our companies at any time of day.

4. Receipt Points to be utilized by Coast includes those identified in Appendix (A) to the Firm Throughput Service Agreement #21374 between Northwestern and Northern Natural Gas Company ("NNG") and any other mutually agreed upon receipt points.

5. Neither party shall have any claim against the other for damages sustained as a result of interruptions of natural gas deliveries caused by Act of God, the elements, labor troubles, strikes, fires, accidents, breakage or repair of pipeline or machinery, or other causes or contingencies beyond the reasonable control of and occurring without negligence on the part of such other party, except that Coast shall act prudently to attempt to replace any interrupted gas deliveries with alternate sources. The parties shall resume delivering and receiving natural gas when such causes or contingencies cease to be operative. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party affected.

6. Northwestern shall pay Coast a management fee of $0.02 per MMBtu for total Northwestern sales throughput, delivered to Northwestern's Zone ABC POI #3096. Coast will provide a load factor discount of $0.01 per MMBtu if Northwestern's load factor for the prior 12 months is greater than 50%. The load factor will be determined by dividing the average daily delivery volume of gas received by Northwestern for the 12 month period by the peak day delivery volume for the same 12 consecutive months immediately prior to the first month of the effective date of the agreement. After the end of each 12 month period, the load factor will be redetermined based on the average daily delivery volume divided by the peak day delivery volume for that just ended 12 month period. The average delivery volume will be determined by dividing the total annual volumes by 365.

7. In addition, Northwestern will pay Coast a share of savings Northwestern realizes as compared to certain Benchmark pricing levels. Such Benchmark levels are provided for this Contract in the attached Exhibits A, B and C. The savings sharing above the Benchmark will be according to the following schedule:

First 12 Months (8/1/99 – 7/31/00) (see Exhibit A)

First $200,000 in savings
Northwestern share 100% Coast share 0%

Next $200,000 in savings
Northwestern share 65% Coast share 35%

All savings over $400,000
Northwestern share 50% Coast share 50%

Second 12 Months (8/1/00 – 7/31/01) (see Exhibit B)

First $200,000 in savings
Northwestern share 100% Coast share 0%

Next $200,000 in savings
Northwestern share 65% Coast share 35%

All savings over $400,000
Northwestern share 50% Coast share 50%

Third 12 Months (8/1/01 – 7/31/02) (see Exhibit C)

First $200,000 in savings
Northwestern share 100% Coast share 0%

Next $200,000 in savings
Northwestern share 65% Coast share 35%

All savings over $400,000
Northwestern share 50% Coast share 50%

Actual purchase costs will be compared to Benchmark costs within 10 days after monthly supply period ends during the term of this Contract. Any shared savings due Coast, plus management fees, will be paid by Northwestern on or before the 20th day of the month following performance.

Notwithstanding the above, if no savings are realized above the Benchmark pricing levels Northwestern will assume 100% of actual costs in excess of Benchmark costs up to $200,000 in each period set out above. Coast agrees to bear 100% of all other excess costs.

8. As part of the services described herein Coast will manage Northwestern's gas storage agreements with NNG. To the extent Coast earns profit from the management of gas supplies delivered into and out of storage, Coast will share 25% of such profit with Northwestern.

9. Either party may request a prospective redetermination of the incremental supplies Benchmark, in writing six months after the effective date of this agreement.

10. To the extent that either party fails to perform its obligations under this Contract, it is the obligation of that party to compensate the other party for the incremental cost, including any penalties or special charges, for obtaining a replacement supply or market.

11. The term of this Contract will be thirty-six (36) months from the effective date shown above, however, the Contract may be terminated by either party upon at least thirty (30) days' written notice period prior to the end of each term in Exhibit A, B and C. If notice of termination is made, the obligations of the parties will continue during such notice period, and for such additional periods of time for performance of obligations in place at the termination date. The parties may mutually agree to extend certain obligations beyond such termination date.

This Contract is executed by the parties on this 21st day of July, 1999.

COAST ENERGY GROUP
Coast Energy Group,
A Division of Cornerstone Propane, L.P.

By: John Boone
Executive Vice President Natural Gas & Crude Oil

Attest: Malcolm Bederman

NORTHWESTERN PUBLIC SERVICE

By:

Title: Exec. V.P. C.E.O.

Attest:

Asst Corporate Secretary

EXHIBIT "A"

BENCHMARKS for SAVINGS this CONTRACT — First 12 Months (366 days) (8/1/99 – 7/31/00)

A.	Coast Contract	November 1, 1999 through March 31, 2000 Benchmark to be determined prior to September 1, 1999
B.	Coast Contract for Carlton	November 1, 1999 through March 31, 2000 A fixed price benchmark will be determined prior to September 1, 1999
C.	Pan Alberta Contract	85% of Ventura Index, 100% Take or Pay
D.	Westcoast Contract	Management Fee: 8/1/99 – 10/31/99 $548.36 per month 11/01/99 – 7/31/00 $562.75 per month Midcon Composite Price x 95% for all gas, 100% Take or Pay
E.	Incremental Supplies	Seasonal
	Nov – March	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374)
	Apr - Oct	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 1.5% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 1.5%

		(TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374)
F.	Capacity Release	$12,600 per month
G.	Other Savings	In connection with any matters not specifically Addressed above in Exhibit "A", Coast will use its good faith efforts to identify to Northwestern any specific item that Coast believes has created savings for Northwestern. Coast and Northwestern agree to negotiate in good faith with one another to establish the validity of the savings. Any such savings realized thereafter by Northwestern shall be included in the amounts to be paid to Coast under the terms of this Contract.
H.	Savings Extending Beyond the Term of The Contract.	Coast and Northwestern agree to negotiate in good faith with one another as to the quantification of any "post-termination" benefits. Neither party shall be prejudiced by the failure of the parties to reach such agreement, and such matters shall be determined as the parties shall mutually agree (including a good faith "agreement not to agree" and subsequent litigation of that specific issue).

COAST ENERGY GROUP

Coast Energy Group,
A Division of Comerstone Propane, L.P.

By: John Boone
Executive Vice President Natural Gas & Crude Oil

NORTHWESTERN PUBLIC SERVICE

By: _____

Title: Pres & C.E.O.

Date: 7-24-98

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EXHIBIT "B"

BENCHMARKS for SAVINGS this CONTRACT		Second 12 Months (365 days) (8/1/00 – 7/31/01)
A.	Coast Contract	November 1, 2000 through March 31, 2001 Benchmark to be determined prior to September 1, 2000
B.	Coast Contract for Carlton	November 1, 2000 through March 31, 2001 A fixed price benchmark will be determined prior to September 1, 2000
C.	Pan Alberta Contract	85% of Ventura Index, 100% Take or Pay
D.	Westcoast Contract	Management Fee: 8/01/00 – 10/31/00 $562.75 per month 11/01/00 – 7/31/01 $579.63 per month Midcon Composite Price x 95% for all gas, 100% Take or Pay
E.	Incremental Supplies	Seasonal
	Nov – March	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374)
	Apr - Oct	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 1.5% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 1.5% (TF capacity relating to the Ventura Index is as

		listed in Northwestern's TF Agreement #21374)
F.	Capacity Release	To be negotiated prior to August 1, 2000.
G.	Other Savings	In connection with any matters not specifically Addressed above in Exhibit "B", Coast will use its good faith efforts to identify to Northwestern any specific item that Coast believes has created savings for Northwestern. Coast and Northwestern agree to negotiate in good faith with one another to establish the validity of the savings. Any such savings realized thereafter by Northwestern shall be included in the amounts to be paid to Coast under the terms of this Contract.
H.	Savings Extending Beyond the Term of the Contract	Coast and Northwestern agree to negotiate in good faith with one another as to the quantification of any "post-termination" benefits. Neither party shall be prejudiced by the failure of the parties to reach such agreement, and such matters shall be determined as the parties shall mutually agree (including a good faith "agreement not to agree" and subsequent litigation of that specific issue).

COAST ENERGY GROUP

Coast Energy Group,
A Division of Cornerstone Propane, L.P.

By: John Boone
Executive Vice President Natural Gas & Crude Oil

NORTHWESTERN PUBLIC SERVICE

By: _____

Title: Pres. & C.E.O.

Date: 7-20-99

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EXHIBIT "C"

BENCHMARKS for SAVINGS this CONTRACT — Third 12 Months (365 days) (8/01/01 – 7/31/02)

A.	Coast Contract	November 1, 2001 through March 31, 2002 Benchmark to be determined prior to September 1, 2001
B.	Coast Contract for Carlton	November 1, 2001 through March 31, 2002 A fixed price benchmark will be determined prior to September 1, 2001
C.	Pan Alberta Contract	85% of Ventura Index, 100% Take or Pay
D.	Westcoast Contract	Management Fee: 8/01/01 – 10/31/01 $579.63 per month 11/01/01 – 7/31/02 $597.02 per month Midcon Composite Price x 95% for all gas, 100% Take or Pay
E.	Incremental Supplies	Seasonal
	Nov – March	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 3% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374)
	Apr - Oct	Baseload Volumes – Ventura 1st of the month index plus 1% Swing Volumes – Ventura BTU Gas Daily Index plus 1.5% (TF capacity relating to the Ventura Index is as listed in Northwestern's TF Agreement #21374) Baseload Volumes - Demarcation 1st of the month Index plus 1% Swing Volumes – Demarcation BTU Gas Daily Index plus 1.5% (TF capacity relating to the Ventura Index is as

listed in Northwestern's TF Agreement #21374)

F.	Capacity Release	To be negotiated prior to August 1, 2001.
G.	Other Savings	In connection with any matters not specifically addressed above in Exhibit "C", Coast will use its good faith efforts to identify to Northwestern any specific item that Coast believes has created savings for Northwestern. Coast and Northwestern agree to negotiate in good faith with one another to establish the validity of the savings. Any such savings realized thereafter by Northwestern shall be included in the amounts to be paid to Coast under the terms of this Contract.
H.	Savings Extending Beyond the Term of the Contract	Coast and Northwestern agree to negotiate in good faith with one another as to the quantification of any "post-termination" benefits. Neither party shall be prejudiced by the failure of the parties to reach such agreement, and such matters shall be determined as the parties shall mutually agree (including a good faith "agreement not to agree" and subsequent litigation of that specific issue).

COAST ENERGY GROUP

Coast Energy Group,
A Division of Comanche Propane, L.P.

By: John Boone
Executive Vice President Natural Gas & Crude Oil

NORTHWESTERN PUBLIC SERVICE

By: [signature]

Title: Group V.P. C.E.O.

Date: 7-20-99

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NORTHWESTERN CORPORATION
ALLOCATIONS TO NORTHWESTERN PUBLIC SERVICE

NorthWestern Corporation ("NOR"), of which NorthWestern Public Service ("NPS") is a division, allocates its expenses and costs to NPS in the following manner:

- A portion of the salaries of the employees of NOR are allocated to NPS, based upon an estimate of the percentage of time spent on activities that are related solely to NPS. The remaining portion of the salaries is allocated to various subsidiaries of NOR.

- An amount equal to the salary allocation is also allocated by NOR to NPS to cover that portion of all benefit plans and other business expenses related to the work of such NOR employees. In other words, no other direct allocations or charging of expenses to NPS for the work of such NOR employees is made.

- The only other expense allocated to NPS from NOR is related to the cost of capital. Based on NOR's capital investment in NPS, as related to NOR's total capital investments, NOR allocates that percentage of its total cost of capital to NPS. This relates to debt and equity investments.

- No other allocations are made by NOR to NPS.

NorthWestern™
PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney
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November 30, 1999

RECEIVED
NOV 30 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard
Executive Director
SD Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Docket No. NG99-002
Initial Brief of NorthWestern Public Service

Dear Mr. Bullard,

I am enclosing the original and ten copies of NorthWestern's initial brief in Docket NG99-002 for filing in this matter.

If you have any questions, please feel free to contact me.

Sincerely yours,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker

NorthWestern™
PUBLIC SERVICE

Russell C. Molstad, Jr.
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Huron, SD 57350-1500
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November 30, 1999

RECEIVED
NOV 30 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms Karen Cremer
S.D. Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Docket No. NG99-002
Initial Brief of NorthWestern Public Service

Dear Karen,

I am enclosing a copy of NorthWestern's Initial Brief in above entitled matter. I have filed the original and ten copies with Mr. Bullard.

If you have any questions, please feel free to contact me.

Sincerely yours,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker

RECEIVED
NOV 30 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	**DOCKET NO. NG 99-002** **INITIAL BRIEF OF NORTHWESTERN PUBLIC SERVICE**

INTRODUCTORY STATEMENT

In this Initial Brief the parties will be referred to as follows: NorthWestern Public Service, a division of NorthWestern Corporation will be referred to as "NorthWestern;" the South Dakota Public Utilities Commission will be referred to as the "Commission;" and the Staff of the Commission will be referred to as the "Staff." Other entities that will be referred to in this brief include: NorthWestern Energy Corporation, a wholly owned subsidiary of NorthWestern Corporation, which will be referred to as "NEC;" Nekota Resources, Inc., a wholly owned subsidiary of NEC, which will be referred to as "Nekota;" Northern Natural Gas Company, an unrelated interstate pipeline company, which will be referred to as "NNG;" Northern Border Pipeline Company, an unrelated interstate pipeline company, will be referred to as "NBPL;" and Northern States Power Company, an unrelated electric and gas utility company, which will be referred to as "NSP." References to the transcript of the hearing held on October 20, 1999, will be by page number as follows: (TR __). Exhibits admitted at the hearing will be referred to by exhibit letter or number as follows: (Exh __).

STATEMENT OF THE CASE

On June 1, 1999, NorthWestern, filed an application with the Commission for an increase in revenues for its South Dakota natural gas operations of $2,108,112 or approximately 6% based upon a test year ending December 31, 1998, as adjusted. Following its review of the filing, the Staff filed its testimony and exhibits, and the parties engaged in settlement discussions. NorthWestern filed rebuttal testimony and exhibits on two issues, and the parties continued their settlement discussions. A proposed Settlement Agreement resolving all issues raised in the proceeding except one was presented to the Commission on October 20, 1999, which proposed settlement was taken under advisement by the Commission on that date, and the revised tariff sheets were approved by the Commission in its Decision and Order Approving Settlement Agreement, dated November 15, 1999, in this matter.

The issue that was the subject of the hearing and which remains to be resolved concerns the collection by NorthWestern, through its adjustment clause, of the capacity charges related to the transportation of natural gas from a NBPL pipeline to NorthWestern's town border station ("TBS") at Aberdeen, South Dakota. During the course of the settlement discussions between Staff and NorthWestern, the parties determined that the issue should be addressed as a purchased gas adjustment clause issue, rather than as an issue in the determination of the base rate cost of service for NorthWestern in this proceeding. Therefore, as part of the Settlement Agreement, the parties agreed as follows: "It is further agreed by the parties that the Nekota pipeline issue which was raised by Commission Staff has been eliminated from the base rate determination, and alternatively will be heard as a Purchase Gas Adjustment request before the Public Utilities Commission on October 20, and October 21, 1999 as a separate proceeding from the base rate determination." Following the Commission

hearing on the proposed settlement on October 20, 1999, a contested hearing was held concerning this issue.

At the conclusion of the hearing, a briefing schedule on that issue was established. This Initial Brief on behalf of NorthWestern is the first submission pursuant to that schedule.

ABSTRACT OF EVIDENCE

In 1996 NorthWestern had in effect an agreement with NNG for pipeline capacity for its South Dakota operations, with a number of delivery points from the NNG interstate pipeline facilities at various TBS in eastern South Dakota, including Aberdeen. As NorthWestern Witness Hitchcock testified at the hearing, during February 1996 NorthWestern experienced a peak day on its South Dakota system, which indicated that existing pipeline capacity on NNG would be insufficient to meet its customers' firm needs (TR 15-16; Exh 1). In particular, on February 1, 1999, firm customer requirements greatly exceeded firm capacity (Exh 1). In fact, NNG advised Mr. Hitchcock that future peak day conditions could potentially require curtailment of firm natural gas loads on NorthWestern's system (TR 16-18).

In addition to concerns about NorthWestern's amount of total firm capacity on NNG to meet a peak day, NorthWestern was also concerned about NNG's ability to deliver the firm capacity (TR 19). Part of this problem was the fact that the Aberdeen TBS was at the end of the NNG pipeline, and complicating it further was the use of natural gas upstream of the Aberdeen TBS on the NNG system by the NSP Pathfinder (now Angus Anson) electric generating plant. As the NSP plant needed large quantities of natural gas to meet its peaking needs, it caused a decrease in pipeline pressure downstream, with the worst problem affecting

service to NorthWestern's Aberdeen TBS and impacting operation of NorthWestern's gas turbine plant in Huron (TR 19).

A further problem for NorthWestern, was the fact that its existing firm capacity on NNG was not aligned properly with its changing customer needs, by community (TR 20).

In order to meet these challenges, NorthWestern and NEC executives began researching feasible alternatives and found the construction of a new pipeline between the NBPL pipeline and NorthWestern's TBS at Aberdeen as the best solution, if contractual commitments to NNG could be renegotiated (TR 21).

Among the commitments that NorthWestern had with NNG was the requirement to use NNG as its exclusive pipeline facility in South Dakota (TR 26-27; Exh 2). Once the alternative pipeline plan had been developed, NorthWestern and NEC executives negotiated with NNG for ways to solve the deliverability problem at Aberdeen; the additional capacity need for NorthWestern; the limitation on exclusive use of NNG to transport natural gas; the need to realign NorthWestern's existing capacity on NNG; and NorthWestern's desire to exchange field capacity, which was not marketable, for market area capacity (TR 19-29).

During the negotiations with NorthWestern NNG was unwilling to change to an earlier implementation date for deliverability solutions for Aberdeen and to discount its transportation charges sufficiently to be a workable alternative for additional firm capacity to the new pipeline (TR 23-25). Because of NNG's insistence that NorthWestern had a commitment to NNG for all of its transportation capacity, NorthWestern formed two subsidiary corporations, NEC and Nekota, to conduct unregulated energy sales and to own alternative delivery facilities, respectively (TR 29-31). With these additional entities providing NorthWestern with flexibility to construct the line as an entity different from

NorthWestern and potentially to market natural gas from the alternative interstate pipeline (NBPL), NorthWestern was able to negotiate with NNG for a solution to meet its challenges (TR 31-32).

NNG, NorthWestern, and NEC formed agreements which provided solutions to NorthWestern's challenges. These agreements provided:

(a) NEC, through Nekota, could construct a pipeline facility from NBPL to Aberdeen to serve NorthWestern, as well as NEC, with NorthWestern free from any claim by NNG that NorthWestern was violating its obligation to transport gas exclusively on NNG (TR 37);

(b) The deliverability (pressure) problem for NorthWestern at Aberdeen would be eliminated because service would come directly from NBPL, through the Nekota pipeline facility, to NorthWestern's Aberdeen TBS, and NBPL did not have the pressure problem at the tap that NNG had in its service line to Aberdeen (TR 37-38);

(c) NorthWestern was allowed to realign its delivery point capacity (including the Aberdeen capacity no longer needed) to better fit its customers' needs at the various TBS on the NNG system (TR 38);

(d) NorthWestern was able to exchange its field capacity on NNG (which NorthWestern had assumed as a result of Federal Energy Regulatory Commission unbundling proceedings) to market area capacity (which could be used by NorthWestern or released for use by other shippers, at an additional value to NorthWestern) (TR 38-39, 42-43, 124, Exh 4); and

(e) NEC would buy additional firm transportation capacity (NNG's TFX service) and additional firm storage capacity (NNG's FDD service) from NNG at an annual cost of $588,000 (TR 74).

As a result of this solution, NorthWestern received transportation charges that were discounted below what NNG was willing to charge ($3.20 as compared to $6.65) (TR 36); a full dedication of the Nekota pipeline to its use, with NEC using only released or excess capacity on days that NorthWestern does not need the capacity (and with NorthWestern only paying for capacity in excess of 15,000/MMBtu/day on the days its use exceeds that amount (TR 43-44); realigned capacity on NNG for all its South Dakota TBS (TR 38, 103-104); and 7,000 MMBtu/day additional capacity at no extra charge that was useful in exchange for capacity that carried little value (TR 38-39, 104). Finally, NorthWestern received additional capacity release opportunities, that averaged more than $200,000 per year, which have been credited to NorthWestern's cost of purchased gas through its PGA clause (TR 42, Exh 2).

NorthWestern included in its purchased gas adjustment filing in December 1996, and in each month's filing thereafter for a period of three years, a reference to the costs associated with this creative solution, labeled "NBPL - ABERDEEN CAPACITY," and reflecting an annual cost of $576,000 (TR 44-45, Exh 5). No Staff questions or Commission proceedings have been conducted, prior to this matter, on the costs included in NorthWestern's adjustment clause related to this project (TR 52-53) either at the time that the Commission Order approved the adjustment initially (Exh 6) or in the adjustment filings made during the three-year period that followed.

ARGUMENTS

(1) The charges for capacity on the Nekota pipeline included by NorthWestern in its PGA filings are just and reasonable and consistent with NorthWestern's adjustment clause.

As discussed in the Abstract of the Evidence, the construction of the Nekota pipeline and the other arrangements made with NNG have been an unqualified success and to the advantage of NorthWestern and its customers. Through a series of creative steps, NorthWestern and NEC have brought benefits of alternative pipeline construction without resorting to litigation or Federal regulatory delays and uncertainty.

Staff Witness Jacobson has attempted to carve from this creative solution only the pipeline construction costs, and then limiting the appropriate capacity charge to a proposed NorthWestern rate of return for such pipeline of 8.53%, the overall rate of return of the Settlement Agreement executed by the parties to the rate case in this matter and approved by the Commission in this matter with regard to the property of NorthWestern. Even if one were to ignore the other costs which were required to provide the benefits which NorthWestern and its customers are enjoying, as a result of this project, the use of NorthWestern's rate of return for Nekota's pipeline is erroneous. In the South Dakota Supreme Court case, In the Matter of the Application of Montana-Dakota Utilities Company, 278 N.W.2d 189 (S.D. 1979), the Supreme Court rejected a similar argument, stating that the rate of return of an affiliated coal company should not be held to the same rate of return as a public utility. The Court reasoned that the coal companies were not subject to the authority of the Commission, and that the appropriate rate of return for a coal company is certainly different from that of a public utility. The case was remanded to the Commission to determine an appropriate rate of return consistent with the coal industry.

Similarly, here the Nekota pipeline is not an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A) because Nekota only serves its parent companies NEC and NorthWestern. NEC's charges to NorthWestern, pursuant to their contract (which charges have been included in NorthWestern's monthly PGA filings since 1996) (TR 67-69, 154-156), are appropriately subject to Commission scrutiny under SDCL 49-34A-19.2, but as detailed above, in addition to the charges detailed in that contract, NEC has incurred significant obligations to provide NorthWestern with this favorable capacity arrangement.

In addition to failing to use the proper standard for measuring the price to be charged by a non-regulated affiliate company in providing products and services to a public utility, Staff Witness Jacobson did not consider the other benefits NorthWestern and its customers receive from the negotiations concluded and obligations incurred to allow the benefits described above. Mr. Jacobson admitted that he did not consider the following benefits that NorthWestern and its customers receive:

(a) NorthWestern's right to use the Aberdeen capacity elsewhere on its system (TR 149);

(b) The improvements to allow NorthWestern to meet its peak day capacity (TR 149-150);

(c) The elimination of the pressure problem at Aberdeen (TR 150);

(d) The ability of NorthWestern to reassign its delivery point capacity throughout its system on NNG, and the ability to avoid point-to-point penalty charges (TR 150);

(e) The exchange for essentially valueless field capacity for valuable market area capacity (TR 150); and

(f) The ability to increase margins for NorthWestern by having increased potential sales to interruptible customers through capacity improvements (TR 151).

Staff Witness Jacobson even testified that he was "highly in support of" some of the above benefits. In summary, Staff failed to consider the whole picture of the arrangement that was necessary in order for NorthWestern to enjoy the significant and long-lasting benefits provided by these steps taken by NorthWestern, NEC, and Nekota.

Exhibit 3 details these benefits, and the numbers shown on that exhibit are worthy of specific discussion here. The $588,000 is the contracted costs incurred to purchase additional capacity from NNG (TR 33, 96-103); $165,000 is the annual return on Nekota's investment in the pipeline itself (TR 33); $23,000 is the annual South Dakota property tax expense for the pipeline (TR 33); and $48,000 is the administrative costs incurred related to the pipeline (TR 34). In dividing that cost responsibility, NorthWestern has proposed to divide the total of these expenses, $824,000 by the proportion that NorthWestern and NEC have of the firm capacity provided by these arrangements with NNG and through the construction of the pipeline. NorthWestern's 15,000 MMBtu capacity, pursuant to its contract with NEC, is 70% of the total additional firm capacity (leaving 30% for NEC) (TR 35-36). Thus NorthWestern has a 70% share, or $576,000 annual cost share, of the total project costs. Had NorthWestern merely purchased additional firm capacity from NNG, it would have paid $1,200,000 annually for such capacity (TR 36-37; Exh 3). In addition, it would have remained obligated to NNG for its exclusive transportation of natural gas (leaving it less options for the future needs of its system), and NorthWestern would not have solved the other problems on its

system including peak day pipeline capacity, less valued field capacity, and delivery point capacity that was not aligned with its needs.

NorthWestern submits that the charges it pays are fair and reasonable, and the arrangement provides significant benefits to NorthWestern and its customers, which the prior arrangement with NNG did not provide. This project was very successful in helping NorthWestern meet a variety of challenges, and at a reasonable cost to its customers. To adopt the Staff's position on this issue would negatively influence other future creative solutions, to the ultimate detriment to NorthWestern and its customers.

(2) The previously filed amended purchased gas adjustment clause filings made by NorthWestern are deemed approved by the Commission and are not subject to refund.

As discussed above and at length at the hearing in this matter, in 1996 NorthWestern faced many challenges in its service of natural gas to customers in South Dakota (TR 14-21). To face these challenges, NorthWestern took a variety of steps, including negotiations with NNG (which resulted in changes in NorthWestern's relationship with NNG which greatly benefited NorthWestern's customers) and ultimately the planning and construction of a natural gas alternative to serve the Aberdeen area (TR 21-41).

After the pipeline was completed, NorthWestern reflected the changes in the cost of natural gas delivered to its distribution system through its natural gas purchased gas adjustment clause ("PGA") pursuant to its South Dakota Gas Rate Schedule (Section No. 3, Sheet 9, et seq) through its monthly PGA adjustment filing. NorthWestern did not call the Staff to describe the adjustment (TR 144); did not otherwise notify the Staff of the particulars of the adjustment (TR 145); and did not provide a "special notice" of the particulars of the adjustment at the time of the filing of the adjustment (TR 139) or at a subsequent meeting

with the Commission and the Staff (TR 145). In hindsight, NorthWestern could have been more specific in identifying the new charges and could have engaged in a dialogue with the Staff on all of the issues discussed above. However, as Staff Witness Jacobson testified at the hearing, the charges that the Staff has recommended be disallowed (such as NorthWestern's share of the $588,000 in new capacity charges paid to NNG) would be a "proper purchased gas adjustment charge" (TR 158). Moreover, by failing to provide a special notice of the particulars of the adjustment, NorthWestern was not trying to hide the adjustment, as NorthWestern Witnesses Leyendecker and Hitchcock both stated (TR 118, 123), but was merely treating it as a non-regulated activity, a part of a solution of which NorthWestern was "very proud" (TR 123).

NorthWestern did provide a PGA filing that listed the adjustment, labeled as "NBPL – ABERDEEN CAPACITY", which provided 15,000 MMBtu of capacity at an annual charge of $576,000 (Exh 5). This same entry was submitted to the Staff for their review every month for three years without the Staff ever asking one question about it (TR 156), even though Staff Witness Jacobson stated that it is part of his responsibilities to review the PGA filings, comparing a new filing to a prior filing and looking for any changes that were questionable (TR 144). Had the Staff asked any questions about the adjustment, the information provided at this hearing could have been provided in 1996.

NorthWestern submits that seeking to discredit either the way this was handled by NorthWestern or by the Staff does nothing to answer the question of whether the capacity charges on the Nekota pipeline are reasonable and appropriate. Earlier in this brief, NorthWestern presented information to support the charge. The only further issue is whether NorthWestern complied with the statutory and tariff provisions concerning the filing of the

three years of PGA filings. As Staff Witness Jacobson testified, there are no Commission rules specifying how the adjustments should be filed (TR 157), or stating that any transactions with an affiliate should be accompanied by any special notice.

Therefore, NorthWestern is to be guided by statute and by its Commission approved tariff with regard to the format and details of information to be provided in a monthly adjustment. The statute, SDCL 49-34A-25, merely states that amended tariffs should be filed with the Commission. NorthWestern's PGA tariff sheet similarly does not provide details as to the information to be provided. Therefore, NorthWestern submits that its monthly filings made that included the Nekota pipeline costs were and are consistent with all prior monthly filings and with the guiding statute and tariff.

SDCL 49-34A-25 provides that when a public utility makes a PGA filing with amended rate schedules, the Commission may determine that an error is made and within ten days may have the public utility place the adjusted rates into effect subject to refund. The statute goes on to provide that if the Commission does not order such rates to be subject to refund, the rates are deemed final. NorthWestern submits and the record supports the conclusion that no order has been entered on any of the monthly PGA filings made for these three years, and therefore, the rates were effective and not subject to refund.

The Staff has recommended that, based on its proposed Nekota Resources Pipeline Adjustment (Exh A), a refund of that adjustment should be made, with interest, for a three-year period be made through a PGA flow-back (TR 139). As discussed above, NorthWestern urges the Commission to determine that the PGA adjustments were not only fair and reasonable, but they also reflect a creative approach by NorthWestern to resolve significant operational and expense issues in a manner that benefited NorthWestern and its customers. If

any portion of the PGA adjustment is found to be excessive, NorthWestern submits that any change in rates resulting from such finding should be prospective only.

CONCLUSION AND REQUEST FOR FINDINGS

In 1996 NorthWestern was faced with a number of challenges. It sought to meet those challenges by coming up with a creative solution that provided its customers with low-cost, reliable natural gas service. The construction of the Nekota pipeline was greatly beneficial to NorthWestern and its customers, and the charges related to the pipeline, and the various costs that NorthWestern and its affiliate companies have undertaken are minor when compared to the benefits derived. The question that the Commission should answer is whether the charges for capacity on the Nekota pipeline in NorthWestern's PGA filings are just and reasonable. If so, then even by Staff's witness's testimony, they are allowable as proper charges (TR 157-158).

Although the transaction was quite complicated, the facts of the case show:

- the deliverability pressure problem from NNG was eliminated;
- NorthWestern was freed of using NNG's pipeline exclusively;
- NorthWestern was able to realign its delivery point capacity to better fit its customers needs;
- NorthWestern was able to exchange field capacity (of little or no value) for valuable market capacity; and
- NorthWestern's customers have enjoyed lower gas costs resulting from released capacity credits.

As Chairman Burg summed up, these benefits cost NorthWestern and its customers $576,000 per year (TR 158), less than the approximately $1,197,000 that would have been payable to NNG just for the additional firm capacity that the Nekota line created. A savings of more

than $500,000 per year, plus the many other benefits discussed above clearly show that the $576,000 PGA adjustment is fair and reasonable.

There is no support either in law or fact for Staff's request that NorthWestern's previously filed amended purchase gas adjustment clause filings are subject to refund. NorthWestern made the PGA filing that was approved by the Commission, and the same adjustment has been included in every monthly filing for three years, in full compliance with statute and NorthWestern's PGA tariff, without any objection, suspension, or order by the Staff or the Commission. NorthWestern will take steps to explain and clarify all future PGA filings, but nonetheless NorthWestern's prior filings were made in compliance with the law.

There is no evidence to indicate NorthWestern did anything unlawful or improper. Furthermore, the only evidence presented shows that the charges were filed in good faith by a company that was very proud of what it had accomplished for its customers. The filings were made properly, were not questioned or challenged by Staff, and became final. NorthWestern submits that the Commission should uphold NorthWestern's PGA adjustment and should adopt the findings attached to this brief as Appendix A.

Dated this 30th day of November, 1999

Respectfully submitted,

NORTHWESTERN PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service

Alan D. Dietrich
Vice President – Legal Administration
NorthWestern Corporation

APPENDIX A

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	DOCKET NO. NG 99-002 PROPOSED FINDINGS OF NORTHWESTERN PUBLIC SERVICE

1. This matter has properly come before the Commission as an issue removed from the consideration in the base rate case determination in this matter, and should be treated as a purchased gas adjustment clause.

2. NorthWestern Public Service has filed and had approved by the Commission, for all time periods relevant in this proceeding, an adjustment clause related to its charges for natural gas in South Dakota.

3. In November and December 1996, and for all monthly periods thereafter to the present, NorthWestern has filed monthly adjustments based on its adjustment clause, which adjustments have not been suspended or otherwise affected by Commission order.

4. NorthWestern and its affiliates have undertaken contract revisions with the interstate pipeline transporter, Northern Natural Gas Company, to provide improved reliability and supply flexibility to NorthWestern's distribution systems.

5. NorthWestern, through its affiliate companies, has constructed a natural gas pipeline facility (the Nekota pipeline) to provide an alternative source of natural gas transportation to its distribution system in the City of Aberdeen, South Dakota.

6. The charges for pipeline capacity paid by NorthWestern on the Nekota pipeline have been included in NorthWestern's adjustment filings since the pipeline was completed in 1996, and such charges are just and reasonable.

7. No refunds of charges made by NorthWestern through its adjustment clause for the Nekota pipeline capacity charges should be made.

8. NorthWestern and the Commission Staff should work together to provide a methodology for review and discussion of any future adjustment clause filings by NorthWestern.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	ORDER APPROVING TARIFF REVISIONS NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application seeks an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission further extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20-21, 1999, starting at 9:00 A.M. CDT, on October 20, 1999, in Room 413, State Capitol, Pierre, South Dakota. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a settlement agreement which increases rates in the amount of $1,279,025. Staff requested that the Commission consider it on October 20, 1999. An issue related to the PGA was separated from the rate case issues and will be decided at a later date.

On October 20, 1999, the Commission convened and considered the settlement agreement along with the presentations of NWPS and Commission Staff and took the matter under advisement. On November 1, 1999, at a regularly scheduled meeting, the Commission approved the settlement agreement with an effective date of December 1, 1999. The Commission ordered NWPS to file new tariffs to reflect the settlement agreement. On November 8, 1999, NWPS filed its tariffs. The revised tariffs are as follows:

South Dakota Gas Rate Schedule, Section No. 2, 7th Revised Sheet No. 1, canceling 6th Revised Sheet No.1
South Dakota Gas Rate Schedule, Section No. 2, 6th Revised Sheet No. 2, canceling 5th Revised Sheet No.2
South Dakota Gas Rate Schedule, Section No. 3, 17th Revised Sheet No. 1, canceling 16th Revised Sheet No.1
South Dakota Gas Rate Schedule, Section No. 3, 3rd Revised Sheet No. 2, canceling 2nd Revised Sheet No.2

South Dakota Gas Rate Schedule, Section No. 3, 8th Revised Sheet No. 3.1, canceling 7th Revised Sheet No. 3.1
South Dakota Gas Rate Schedule, Section No. 3, 7th Revised Sheet No. 4.1, canceling 6th Revised Sheet No. 4.1
South Dakota Gas Rate Schedule, Section No. 3, 8th Revised Sheet No. 6.1, canceling 7th Revised Sheet No. 6.1

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, and 49-34A-23.

At its November 15, 1999, meeting, the Commission considered whether to approve the tariff sheets. The Commission voted unanimously to approve the rate schedules and related tariff sheets. Based upon the settlement agreement, the Commission finds that the rate schedules and related tariff sheets are consistent with the revenue levels and rate design agreed to in the settlement agreement. It further finds that the filing is just and reasonable and shall be approved. It is therefore

ORDERED, that the above mentioned proposed tariffs are approved and shall be effective for billings rendered on and after December 1, 1999.

Dated at Pierre, South Dakota, this 8th of December, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Melanie Kelley

Date: 12/8/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg
JAMES A. BURG, Chairman

Pam Nelson
PAM NELSON, Commissioner

Laska Schoenfelder
LASKA SCHOENFELDER, Commissioner



South Dakota Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

January 7, 2000

Mr. Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service
600 Market Street West
Huron, SD 57350

Mr. Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street S.E.
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Re: In the Matter of the Application of NorthWestern Public Service for Authority to Increase Rates for Natural Gas Service
Docket NG99-002

Dear Sirs:

Enclosed each of you will find a copy of Brief of Commission Staff in the above captioned matter. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

KEC:dk
Enc.

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Jim Burg
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Charlene Lund
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Keith Senger
Rolayne Ailts Wiest

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	BRIEF OF COMMISSION STAFF NG99-002

PRELIMINARY STATEMENT

On June 1, 1999, NorthWestern Public Service (NWPS), a division of NorthWestern Corporation, filed with the Public Utilities Commission (Commission) an application to increase its natural gas rates in South Dakota. The Commission held a hearing on October 20, 1999, on the issue of payments made by NWPS to its affiliate NorthWestern Energy Corporation for the purchase of pipeline capacity from Nekota. For purposes of this brief, NorthWestern Energy Corporation, a wholly owned subsidiary of NorthWestern Corporation, will be referred to as NEC; Nekota Resources, Inc., a wholly owned subsidiary of NEC will be referred to as Nekota; Northern Natural Gas Company, an interstate pipeline company, will be referred to as NNG; Northern Border Pipeline Company, an interstate pipeline company, will be referred to as NBPL; and the Federal Energy Regulatory Commission will be referred to as FERC. References to the transcript of the hearing will be by page number as follows: TR ___. Exhibits admitted at the hearing will be referred to by exhibit letter or number as follows: Exh ___.

STATEMENT OF THE CASE

On June 1, 1999, NorthWestern Public Service (NWPS), a division of NorthWestern Corporation, filed with the Public Utilities Commission (Commission) an application to increase its natural gas rates in South Dakota. The application sought an overall increase

in rates in the amount of $2,108,112 or approximately 6%. NWPS requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission further extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20, 1999. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a proposed settlement agreement which would increase NWPS' natural gas rates in the amount of $1,279,025. By mutual agreement of the parties, the issue related to the payments made by NWPS to its affiliate NEC for the purchase of pipeline capacity from Nekota, was separated from the rate case issues. The parties also agreed to present this issue to the Commission on October 20, 1999, following the proposed settlement agreement discussion.

On October 20, 1999, the Commission convened and considered the proposed settlement agreement. The Commission took the matter under advisement and on November 1, 1999, the Commission approved the settlement agreement with an effective date of December 1, 1999. Also on October 20, 1999, the Commission heard Commission Staff's and NWPS' respective cases on the issue of payments made by NWPS to its affiliate NEC for the purchase of pipeline capacity from Nekota. At the close of the evidence, a briefing schedule was established. Commission Staff files this brief in accordance with the briefing schedule.

ARGUMENT AND AUTHORITY

ISSUE I

PAYMENTS MADE BY NWPS TO ITS AFFILIATE NEC FOR THE PURCHASE OF PIPELINE CAPACITY FROM NEKOTA ARE EXCESSIVE AND THEREFORE NOT JUST AND REASONABLE.

NWPS states in its brief that the construction of the Nekota pipeline and other arrangements made with NNG have been an unqualified success and that through a series of creative steps NWPS and NEC have brought benefits of alternative pipeline construction to its shareholders and ratepayers without resorting to litigation or federal regulatory delays. NWPS' position begs the issue in this case which is, are the payments made by NWPS to its affiliate NEC for the purchase of pipeline capacity from Nekota excessive and therefore not just and reasonable.

Commission Staff would submit that the capacity charges passed through the PGA to ratepayers are excessive and therefore not just and reasonable. Commission Staff recommends that the capacity charges be reduced to a level that reflects Nekota's cost of providing the capacity and that the adjustment be made effective retroactive to December 1996, when the costs were first passed through the PGA.

In support of its position, Commission Staff will provide a factual summary of the issue and then discuss the legal rationale and present its argument.

A. FACTUAL SUMMARY

Unbeknownst to Commission Staff, NEC through Nekota constructed a pipeline from NBPL to Aberdeen to serve NWPS' customers. TR 65. The pipeline was completed in late 1996 and cost $1,185,000. TR 56, 66. In December 1996, NWPS changed its tariff format

from its previous format. Exh B and 5. Within its December 1996 PGA filing, NWPS began placing a line item described only as "NBPL-Aberdeen $576,000". Exh 5, pg 14.

During its review of NWPS' filing in the instant base rate case, Commission Staff discovered that this entry [NBPL-Aberdeen capacity] did not represent an interstate transportation service or pipeline rate approved by the FERC but was, in fact, a payment made pursuant to a series of private pipeline capacity and other contracts among NWPS, its subsidiary NEC, and NEC's subsidiary, Nekota for "unregulated" services at an "unregulated" rate. Commission Staff investigated these transactions as part of its investigation of all of the transactions between NWPS and its affiliates, as reported in Statement R of its rate filing and concluded that these "NBPL-Aberdeen capacity" charges are and have been excessive and therefore, unjust and unreasonable.

The important facts underlying Commission Staff's conclusion are not in serious dispute. The Nekota pipeline represents an investment of $1,185,000. It has an expected life of at least 20 years (the longest term of either of the service contracts which, undoubtedly is less than the expected physical life of the pipeline). Annual property taxes in 1998 amounted to $23,326. Operation and maintenance expenses are paid directly by NWPS and automatically are reflected in its base rates. The rate of return that should be applied to the Nekota pipeline investment is in dispute, but not seriously so. Commission Staff recommended a return on equity in this case which when combined with the other cost of service elements indicated a levelized annual revenue requirement of $172,815. Exh A. This is the revenue requirement related to the pipeline's entire capacity even though NWPS contractually is entitled to only 62.5% of the capacity.

A corresponding calculation made by NWPS suggests an annual revenue requirement of $185,000 or, if an unsupported allowance for "administrative costs" is included, $233,000. Exhibit 3, sum of Pre-tax return, Property taxes and Administrative costs; TR 33-34; 159. Thus, whether one uses Commission Staff's determination or either determination developed from NWPS' calculations, the utility-type revenue requirement is far less than the $576,000 per year that has been and continues to be charged to NWPS' ratepayers as a Purchased Gas Adjustment.

B. LEGAL RATIONALE

NWPS faults Commission Staff for only permitting NWPS to claim its pipeline construction costs and not all of its creatively generated benefits. Commission Staff is following the mandate of the law found in SDCL 49-34A-25, set forth below.

> 49-34A-25. The commission shall permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service *in direct relation* to changes in wholesale rates for energy delivered, the delivered costs of fuel used in generation of electricity, the delivered cost of gas, ad valorem taxes paid, or commission approved fuel incentives. The amended rate schedules shall be filed with the commission on or before the effective date of the change in costs, and if the commission determines that the revised rate schedule *is in error*, the commission may within ten days of receipt thereof require by order the public utility to file a bond or other security upon such terms and conditions as the commission may require and for such purposes as contained in §§ 49-34A-17 and 49-34A-22. Such rates may go into effect on the date of the change in costs subject to the above refund provisions. Failure of the commission to enter an order in regard thereto shall be deemed approval. The public utility may appeal such order pursuant to and in accordance with § 49-34A-62.

(emphasis added)

SDCL 49-34A-25 clearly permits public utilities to automatically adjust charges for public utility services that are <u>in direct relation</u> to changes in its delivered gas cost. NWPS

has, on its own, not only automatically passed through costs that are in direct relation to changes in its delivered cost of gas but has included costs that are not permissible under the statute. These costs have no quantitative value or relevance to the ratepayers but are merely "creative" costs. SDCL 49-34A-25 does not permit NWPS to assess its ratepayers for creatively generated "benefits" and NWPS has failed to cite to any statutory authority that would permit such costs to be an automatic pass through.

Also SDCL 49-34A-25 refers only to errors found in the filing--not unreasonable rates. The Legislature clearly did not intend to give the Commission or its staff only 10 days to assess the reasonableness of commodity, and delivery costs and purchasing practices. The practical effect of NWPS' reading of the statute would be that there would be no time for investigation and bonding would be required for each filing in order to complete a prudence review.

NWPS objects to Commission Staff's conclusion on the grounds that its analysis fails to comprehend the full scope, cost and benefits of the Nekota "project." When other elements are considered, the $576,000 annual charge is justified, according to NWPS. Indeed, in Exhibit 3, NWPS purports to show that the total project annual cost is $824,000 of which it would allocate $576,000 to NWPS in recognition of the fact that some project benefits are retained by NEC.[1]

NWPS' efforts to broaden the analysis are misguided and unconvincing. It argues, in essence, that it found itself between a rock and a hard place with its supplier NNG in

[1] NWPS does not explain why it would allocate 70% of the project costs to NWPS when its contract with NEC assigns to it only 15,000 Mmbtu/day, or 62.5%, of the pipeline's 24,000 Mmbtu/day capacity.

1996. It needed a larger firm supply at Aberdeen and it desired to redistribute its entitlements from NNG and to solve pipeline pressure problems. Although an alternative connection to NBPL was possible, it had earlier agreed that NNG would be its exclusive supplier for 10 years and such a commitment left it with no bargaining power for discounts from NNG's high rates. Consequently, as it now explains, NWPS entered into a "buy-out" agreement with NNG whereby NNG agreed not to prevent NWPS from establishing, through NEC/Nekota, a connection with NBPL at Aberdeen. For this concession, NEC agreed to purchase additional capacity for transportation and deferred delivery service from NNG at an annual cost that is said to be $588,000[2]

While the $588,000 charge is described as a "buy-out" cost incurred by NEC, NWPS acknowledges that it also represents the purchase of capacity. But it was unable to provide a breakdown. TR 101. This is not surprising because, in fact, (as admitted at TR 96) the *entire* amount was calculated by applying NNG's then-effective rates to the billing determinants representing the services being purchased. Thus, the fact is that NEC has agreed to purchase capacity and deferred delivery services from NNG and it (NEC, the unregulated marketer) has the right to profit from the use of these services; they are not dedicated to NWPS.

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[2] In fact, this amount is not supported in the record. Moreover, NWPS admits that the amount, which apparently was calculated at the time the Nekota/NEC contracts were executed, "could be higher or lower than [$588,000]" (TR 97-98).

In addition, NWPS acknowledges that the contracts for these services are for a term of five years, yet it relies on the $588,000 annual cost to support the Nekota pipeline charges to NEC and NWPS that will be in effect for ten years. (TR 101-102)

NWPS also suggests that substantial benefits flow from its Nekota project solution. It points to credits flowed through to ratepayers as the result of its release of pipeline capacity, but these credits existed before the Nekota project-related agreement with NNG and, moreover, they are affected by other factors affecting pipeline utilization, such as weather conditions. Furthermore, the operating "benefits" that may have resulted from the "Nekota Pipeline Project" are operating improvements that are expected from a well-operated utility that itself benefits from being the monopoly provider of an essential service to the public.

Commission Staff believes that the buy-out costs, in addition to the capacity charges, created by NWPS to be passed on to ratepayers are excessive and therefore not just and reasonable. The amount NWPS has already passed on to ratepayers and wants to continue to pass on greatly exceeds Nekota's cost of providing service. Nekota's investment in the pipeline is $1,185,000. For such an investment an annual rental of $576,000 is excessive on its face. Combine that with the facts that the facility has an expected life of at least 20 years, that only 62.5% of the capacity of this line is committed to NWPS, and that by separate agreement NWPS is obligated during the first 5 years of its contract to pay all its inspection costs and operation and maintenance expenses, clearly demonstrates that the charge is excessive, unreasonable, and unjustified. TR 137.

NWPS also faults Commission Staff for recommending that the rate of return on the Nekota pipeline be 8.53%. Exh A. Commission Staff believes that its recommended rate of return is appropriate in this case and not erroneous as it was not calculated in the same manner as a traditional rate case calculation. TR 139. Commission Staff proposed a fixed

monthly charge based on a 20-year contract life as opposed to a calculation based on the physical life of the pipe. This reflects ownership by the affiliate as opposed to ownership by NWPS. TR 139-140. NWPS has made no comparisons between Nekota's rate and "industry standards." Only NNG's maximum rate was used for an industry standard and it is an interstate pipeline regulated by the FERC. No bids were sought by NWPS for a comparable pipeline built and owned by others. TR 66. Thus NWPS has not met the court's ruling in Application of Montana-Dakota Utilities Company for Authority to Establish Increased Rates for Electric Service, 278 N.W.2d 189 (S.D. 1979).

Commission Staff's proposal comports with Application of Montana-Dakota Utilities Company for Authority to Establish Increased Rates for Electrical Service. In the MDU case the South Dakota Supreme Court affirmed the Commission's decision and order which found that MDU's wholly-owned subsidiary, Knife River, had earned unreasonable profits on the sale of its coal to MDU. The Court remanded the case to circuit court for remand to the Commission with instructions to set a rate of return for Knife River which comports with a reasonable rate of return in light of the five-company average in the sample which had been submitted into evidence. Id. at 193.

In reaching its decision, the Supreme Court reaffirmed the Commission's statutory authority pursuant to SDCL 49-34A-19.2 to analyze the reasonableness of profits paid to supplier subsidiaries in determining the revenue requirements allowable to a regulated utility and to disallow profit which is unreasonable. According to the Court, such a statute "embodies the concept to which we have adhered for decades, that is, prices and profits paid to affiliates and subsidiaries *must be reasonable*. In determining reasonableness, the

Commission is not restricted to any single formula in arriving at the rates fixed for MDU 'so long as the method followed and the order entered when applied to the facts and viewed as a whole do not produce an unjust or arbitrary result.' *We are more concerned with the result which is reached than with the method employed.*" (cites omitted) (emphasis added) Commission Staff's recommended rate is an industry representative rate as previously determined by the Commission in other pipeline rate proceedings.

As the Supreme Court noted, the burden is on the utility to prove that no unreasonable profits were involved in the sale between the parent and its subsidiary. In this case, NWPS has failed to meet its burden. Ratepayers are paying $5,760,000 for a pipeline that cost $1,185,000 to build (10 years at $576,000). According to NWPS' own witness, a good portion of the $5,760,000 is "buy-out dollars or whatever you want to call it, in order for NPS [NWPS] to use another pipeline rather than Northern" rather than a charge for capacity on the pipeline. TR 74. Unfortunately it is not possible to determine the basis for the $588,000 buy-out dollars that NWPS claims is reasonable as NWPS never provided that information or any other late filed exhibits as it stated it would at the October 20th hearing.[3]

NWPS argues that the $588,000 is an unfortunate project cost that it had to incur to bypass NNG. TR 74. Commission Staff would submit that even if the decision to build

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[3]NWPS' witnesses and attorneys stated they would file the following documents as late filed exhibits but never did so: (1) calculation for pre-tax return, TR 75; (2) volumes as it relates to Exhibit 4, TR 70; (3) contract between NNG and NEC, TR 98; (4) contract between NEC and NPS, TR 99. Commission Staff would now object to any filing of the exhibits after Commission Staff has filed its brief as it would have no opportunity to comment on such exhibits.

a pipeline to bypass NNG was necessary, it does not follow that all costs associated with that decision are reasonable and prudent and therefore capable of being passed on to the ratepayer. In Consumer Power Company v. Michigan Public Service Commission, et al., 572 N.W.2d 222 (Mich. App. 1997), the natural gas local distribution company, Consumer Power Company (Consumers), entered into a discount rate contract with James River, one of Consumers' largest gas transportation customers, to prevent James River from by-passing Consumers' system. Consumers requested the Michigan Public Service Commission (PSC) to approve the contract. The PSC approved the contract with the condition that Consumers' shareholders assume full responsibility for absorbing much, if not all, of any revenue shortfall caused by the pricing and other contract terms that the utility negctiated. Id. at 226.

Consumers appealed. The Michigan Court of Appeals upheld the decision of the PSC finding that the mere fact that the PSC allowed Consumers and James River to proceed with their contract in no way constitutes any express or implied determination that any of the costs of keeping James River as a customer are the kind of reasonable and necessary costs of doing business that may be charged to Consumers' other ratepayers, especially since the PSC specifically conditioned its approval of the special discount upon the proviso that some, if not all, of the resulting revenue shortfall must be borne solely by Consumers' shareholders. Id. at 228. The Court of Appeals went on to state, "even when the PSC does find that a particular business decision is reasonable and prudent, it does not necessarily follow that the PSC must also find all the costs associated with that decision reasonable and prudent as well." Id. at 229.

The same situation exists in this case. NWPS claims numerous creatively generated benefits were gained through the building of the pipeline. These benefits may well exist, however most of the claimed benefits are not relevant to the ratepayers and it is the shareholders who received the majority of the benefits. Accepting Commission Staff's proposal would not affect any of these benefits. TR 140. On the other hand, acceptance of NWPS' plan would forever harm the ratepayer.

ISSUE II

THE COMMISSION CAN ORDER A REFUND IF IT DETERMINES THAT NWPS OVERCHARGED THE RATEPAYERS.

NWPS states that its monthly PGA filings were consistent with all prior monthly filings and with the guiding statute and tariff; that the PGA adjustments were fair, reasonable, and creative; and that if the Commission determines that the adjustment is excessive that any change in rates should be prospective only. NWPS brief pg. 12-13.

Commission Staff's recommendation at the hearing was that the charges passed through the PGA to ratepayers be reduced to a level that reflects Nekota's cost of providing the capacity and that the adjustment be made effective retroactive to December 1996, when the costs were first passed through the PGA. Commission Staff further recommended that the principal amount of the overcharges, together with accrued interest be flowed back to ratepayers over a 3 year period in the PGA.

In support of its recommendation, Commission Staff will provide a factual summary of the issue and then discuss the legal rationale and present its argument.

A. FACTUAL SUMMARY

The format of NWPS' PGA tariff changed drastically in December 1996. Exh B and 5. Coincidently that was the same time that South Dakota was suffering from a tremendously cold winter which increased the volumes of natural gas being used by ratepayers. TR 42. Also coincidentally, December 1996, was the first time NWPS included a new entry on its PGA identified only as "NBPL-Aberdeen" which was submitted in a comprehensive restructuring of the majority of NWPS' entire gas tariff. Exh 5. Commission Staff was never informed that the pipeline charge or a transaction with an affiliate was now to be found on the monthly PGA tariff. TR 145.

B. LEGAL RATIONALE

The Commission has the authority and responsibility to reduce the PGA charges to a level that reflects Nekota's cost of providing capacity to NWPS and to order a refund of the overcharges from December 1996, through the present.

SDCL 49-34A-6 and 49-34A-26, set forth below, grants the Commission such authority.

> 49-34A-6. Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.
>
> 49-34A-26. On its own motion or upon a complaint made against any public utility, by the governing body of any political subdivision, by another public utility, or by any twenty-five consumers of the particular utility *that any of the rates, tolls, tariffs, charges, or schedules or any joint rate or any regulation, measurement, practice, act or omission affecting or relating to the transmission, delivery or furnishing of natural gas or electricity or any service*

> *in connection therewith is in any respect unreasonable, insufficient or unjustly discriminatory,* or that any service is inadequate or cannot be obtained, the Public Utilities Commission shall proceed, with notice, to make such investigation as it may deem necessary and *take such action as deemed necessary and appropriate.*

(emphasis added)

NWPS attempts to argue that its overcollection through the PGA since December 1996, cannot be subject to refund because neither Commission Staff nor the Commission raised the issue of overcollection within 10 days of filing the PGA tariff. NWPS' argument lacks merit for 4 reasons. First, if the Commission is only allowed to adjust any rates, tolls, tariffs, charges, or schedules or any joint rate or any regulation, measurement, practice, act or omission affecting or relating to the transmission, delivery or furnishing of natural gas or any service in connection therewith within a 10 day timeframe, the language found in SDCL 49-34A-26 that the Commission "shall proceed, with notice, to make such investigation as it may deem necessary and take such action as deemed necessary and appropriate" would be rendered meaningless. Second, if any such argument were to prevail, public utility shareholders would be rewarded and ratepayers forever harmed if a wrong rate, toll, tariff, charge, or schedule or any joint rate or any regulation, measurement, practice, act or omission affecting or relating to the transmission, delivery or furnishing of natural gas or any service in connection therewith were to be implemented and could not be corrected. Third, a policy such as that suggested by NWPS would only encourage public utilities to try to "slip one by" Commission Staff and the Commission as there would be no penalty if caught. In fact, the public utility shareholder would be rewarded by an overcollection that need not be returned to the ratepayers. Fourth, as

discussed in Issue I, the 10 day limit only applies to situations where there is an error in the tariff filing and not those situations where there is a finding that the tariff is unreasonable.

There is no question that NWPS did not tell Dave Jacobson, the person who is primarily responsible for reviewing the PGA, that the December 1996 PGA filing contained any information relating to the Nekota pipeline charge or that there was a transaction with an affiliate. There is no evidence that NWPS informed any Commissioner or Commission Staff member of this change at any time including during the comprehensive tariff restructuring completed in docket NG96-015. TR 141, 144-145. Further, an NWPS witness admitted that unless that item (NBPL-Aberdeen) were specifically pointed out, it would not be possible to know that that was a transaction with an affiliate. TR 68. NWPS also admitted the monthly PGA filings never used the word "Nekota" or "NEC". TR 68. NWPS also admits that it never told Commission Staff about building the pipeline. TR 65. Without any knowledge of these events it was impossible to have raised the issue within any period of time.

SDCL 49-34A-6 is self-explanatory, rates must be reasonable and just. Unjust and unreasonable rates are prohibited. Assessing ratepayers $5,730,000 for a $1,185,000 pipeline is unjust and unreasonable.

Commission Staff would submit that the law as found in SDCL 49-34A-6 and 49-34A-26 as well as case law allows for a refund of an overcollection. In Northern Michigan Water Company v. Michigan Public Service Commission, 147 N.W.2d 707 (Mich. App. 1967), rev'd on other grounds, the Michigan Public Service Commission issued an order

approving the plaintiff's rate increase from and after the date of the order and further ordered that refunds be made to the plaintiff's customers for rates charged without prior commission approval. On appeal, the Michigan Court of Appeals, in reversing and remanding the case to the circuit court for an order affirming the public service commission stated, "[W]hile the public service commission may not retroactively order a utility to refund charges previously approved by the commission, the commission may lawfully require a public utility to refund charges collected without its approval." Id. at 710.

The situation here demands the same. The Commission never approved NWPS' overbilling of the PGA. The Commission could not have approved that of which it had no knowledge. NWPS admits it never specifically told Commission Staff or the Commission of its building of the pipeline let alone the charges that were being passed on to ratepayers. TR 139, 144-145.

The Commission has ample statutory authority found in SDCL 49-34A-6 and 49-34A-26 to order a refund of the overcollection of PGA rates. Commission Staff would recommend that the Commission find that the rates currently charged by NWPS are unjust and unreasonable; that the overcollection from December 1996, through the present be refunded with interest; and that the PGA rate be reduced to a level that reflects Nekota's cost of providing the capacity to NWPS.

CONCLUSION

The issue in this matter is quite simple, that is, the payments made by NWPS to its affiliate NEC for the purchase of pipeline capacity on the Nekota pipeline were excessive and therefore unjust and unreasonable. The charges passed through the PGA should be

reduced to a level that reflects Nekota's cost of providing the capacity. Statutory law provides that the adjustment be made effective retroactive to December 1996, to the present. The principal amount of the overcharges, together with accrued interest, should be flowed back to ratepayers over a 3 year period in the PGA.

Dated at Pierre, South Dakota, this 7th day of January, 2000.

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501
Telephone (605) 773-3201

CERTIFICATE OF SERVICE

I hereby certify that copies of Brief of Commission Staff were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this the 7th day of January, 2000.

Mr. Russell C. Molstad, Jr.
Corporate Attorney
NorthWestern Public Service
600 Market Street West
Huron, SD 57350

Mr. Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street S.E.
Huron, SD 57350

Karen E. Cremer

Karen E. Cremer
Staff Attorney

NorthWestern
PUBLIC SERVICE

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January 11, 2000

RECEIVED
JAN 12 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard
Executive Director
SD Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: NG99-002 Late Filed Exhibits

Dear Mr. Bullard,

Enclosed you will find the requested late filed exhibits: (1) calculation for pre-tax return, TR 75; (2) volumes as it relates to Exhibit 4, TR 70; (3) contract between NNG and NEC, TR 98; and (4) contract between NEC and NPS, TR 99. Would you please file these exhibits with the rest of the file in this matter.

I apologize for the oversight in not filing these documents sooner. NorthWestern would have no objection to Commission Staff having until January 21 to file additional comments in this matter as it pertains to these documents.

If you have any questions, please feel free to contact me.

Sincerely,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Tom Hitchcock
Rod Leyendecker
Alan Dietrich

NorthWestern™
PUBLIC SERVICE

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January 11, 2000

RECEIVED
JAN 12 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms Karen Cremer
S.D. Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Late Filed Exhibits

Dear Karen,

I am enclosing your copy of the late filed exhibits which are as follows: (1) calculation for pre-tax return, TR 75; (2) volumes as it relates to Exhibit 4, TR 70; (3) contract between NNG and NEC, TR 98; and (4) contract between NEC and NPS, TR 99. Would you please file these exhibits with the rest of the file in this matter.

I apologize for not filing these sooner. If you would like, NorthWestern would have no objection to you having until January 21 to file any additional comments in this case as it pertains to these late filed exhibits.

If you have any questions, let me know.

Sincerely,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker

Calculation for pre-tax return, TR 75

NorthWestern Partner Entities
1996 Pipeline Capacity Project
Determination of Return on Investment
Test Year Ended December 31, 1998

Line No.	Description	Amounts
	(a)	(b)
1	**Cost of Service - Warner Pipeline @**	
2	**Regulated Rates of Return Approved**	
3	**in NPS Docket No. NG94-008**	
4	Capital Component Ratio	
5	Long-term debt	52.44%
6	Preferred stock	1.13%
7	Common stock	46.43%
8	Capital Component Rate	
9	Long-term debt	7.28%
10	Preferred stock	4.52%
11	Common stock	11.25%
12	Capital Component Weighted Cost	
13	Long-term debt	3.82%
14	Preferred stock	0.05%
15	Common stock	5.22%
16	Overall	9.09%
17	Income Taxes on Return	2.84%
18	Pre-tax Return	11.93%
19	Actual Capital Cost	$1,185,397.04
20	Levelized Pre-tax Operating Income - 20 YR	$158,003.70
21	**Test Year Actual Rates of Return**	
22	**Utilizing Capital Structure and Embedded**	
23	**Debt and Preferred Stock Costs Approved**	
24	**in NPS Docket No. NG94-008**	
25	Capital Component Ratio	
26	Long-term debt	52.44%
27	Preferred stock	1.13%
28	Common stock	46.43%
29	Capital Component Rate	
30	Long-term debt	7.28%
31	Preferred stock	4.52%
32	Common stock	12.34%
33	Capital Component Weighted Cost	
34	Long-term debt	3.82%
35	Preferred stock	0.05%
36	Common stock	5.73%
37	Overall	9.60%
38	Income Taxes on Return	3.11%
39	Pre-tax Return	12.71%
40	Actual Capital Cost	$1,185,397.04
41	Test Year Pre-tax Operating Income - 20 YR Average	$165,843.78

NorthWestern Partner Entities
1996 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	January	February	March	April	May	June
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Revenues**						
2	MDQ - MMBtus:						
3	NPS Aberdeen Primary Firm Capacity	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0
4	NPS Aberdeen Secondary Firm Capacity	0.0	0.0	0.0	0.0	0.0	0.0
5	NEC Aberdeen Secondary Firm Capacity	1,898.4	1,615.0	1,761.3	1,240.0	1,254.8	1,163.3
6	NEC Northern Natural Primary Firm Capacity	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0
7	Transfer Rate	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20
8	Transfer Revenues:						
9	NPS Aberdeen Primary Firm Capacity	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00
10	NPS Aberdeen Secondary Firm Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	NEC Aberdeen Secondary Firm Capacity	$6,074.88	$5,168.00	$5,636.16	$3,968.00	$4,015.36	$3,722.56
12	NEC Northern Natural Primary Firm Capacity	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00
13	Total Revenues	$70,074.88	$69,168.00	$69,636.16	$67,988.00	$68,015.36	$67,722.56
14	**Expenses**						
15	Northern Natural Gas Services:						
16	Primary Firm Pipeline Capacity						
17	Demand Charges	$22,435.00	$22,435.00	$22,360.00	$19,385.00	$19,715.00	$19,715.00
18	Commodity Charges	$10,943.00	$9,884.00	$10,850.00	$4,500.00	$4,650.00	$4,500.00
19	Fuel Reimbursement	$6,794.27	$5,542.88	$6,731.65	$6,605.40	$6,731.65	$4,474.94
20	Firm Deferred Delivery						
21	Capacity & Reservation Charges	$7,653.61	$7,653.61	$7,653.61	$7,653.61	$7,653.61	$26,025.61
22	Injection / Withdrawal Charges	$1,575.30	$575.36	$576.33	$338.61	$0.00	$799.87
23	Fuel Reimbursement	$0.00	$0.00	$0.00	$0.00	$0.00	$955.39
24	NEC Management Fees	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00
25	1998 Property Taxes - Paid in 1999	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85
26	Total Expenses	$55,345.03	$52,034.70	$54,115.44	$44,426.47	$44,694.11	$62,414.66
27	**Pre-tax Operating Income**	$14,729.85	$17,133.30	$15,520.72	$23,541.53	$23,321.25	$5,307.90

NorthWestern Partner Entities
1996 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	July	August	September	October	November	December	Year
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Revenues**							
2	MDQ - MMBtus:							
3	NPS Aberdeen Primary Firm Capacity	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	15,000.0	180,000.0
4	NPS Aberdeen Secondary Firm Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	NEC Aberdeen Secondary Firm Capacity	1,103.2	1,085.5	1,203.3	1,706.5	1,966.7	1,980.6	17,978.6
6	NEC Northern Natural Primary Firm Capacity	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	60,000.0
7	Transfer Rate	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20	$3.20
8	Transfer Revenues:							
9	NPS Aberdeen Primary Firm Capacity	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$48,000.00	$576,000.00
10	NPS Aberdeen Secondary Firm Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	NEC Aberdeen Secondary Firm Capacity	$3,530.24	$3,473.60	$3,850.56	$5,460.80	$6,293.44	$6,337.92	$57,531.52
12	NEC Northern Natural Primary Firm Capacity	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$16,000.00	$192,000.00
13	Total Revenues	$67,530.24	$67,473.60	$67,850.56	$69,460.80	$70,293.44	$70,337.92	$825,531.52
14	**Expenses**							
15	Northern Natural Gas Services:							
16	Primary Firm Pipeline Capacity							
17	Demand Charges	$19,580.00	$19,580.00	$19,580.00	$19,580.00	$19,710.00	$19,710.00	$243,785.00
18	Commodity Charges	$4,650.00	$4,650.00	$4,500.00	$4,650.00	$10,515.00	$10,865.50	$85,157.50
19	Fuel Reimbursement	$5,442.76	$4,431.27	$3,635.89	$4,623.94	$3,859.00	$4,246.79	$63,120.44
20	Firm Deferred Delivery							
21	Capacity & Reservation Charges	$26,025.61	$26,025.61	$26,025.61	$26,025.61	$7,768.08	$7,768.08	$183,932.26
22	Injection / Withdrawal Charges	$967.22	$551.22	$666.62	$829.35	$251.71	$651.08	$7,782.67
23	Fuel Reimbursement	$1,359.84	$630.94	$646.93	$990.53	$0.00	$0.00	$4,583.63
24	NEC Management Fees	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$4,000.00	$48,000.00
25	1998 Property Taxes - Paid in 1999	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.85	$1,943.89	$23,326.24
26	Total Expenses	$63,969.28	$61,812.89	$60,998.90	$62,643.28	$48,047.64	$49,185.34	$659,687.74
27	**Pre-tax Operating Income**	$3,560.96	$5,660.71	$6,851.66	$6,817.52	$22,245.80	$21,152.58	$165,843.78

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NorthWestern Partner Entities
1998 Pipeline Capacity Project
Actual Operating Results by Flow Month
Test Year Ended December 31, 1998

Line No.	Description	January	February	March	April	May	June
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Fuel Reimbursement**						
2	Primary Firm Pipeline Capacity - NNG						
3	Monthly Receipts - MMBtus	155,000.0	140,000.0	155,000.0	150,000.0	155,000.0	150,000.0
4	Fuel Reimbursement %	1.98%	1.98%	1.98%	1.98%	1.98%	1.53%
5	Fuel Gross-up - MMBtus	158,131.0	142,828.0	158,131.0	153,030.0	158,131.0	152,330.7
6	Fuel Reimbursement - MMBtus	3,131.0	2,828.0	3,131.0	3,030.0	3,131.0	2,330.7
7	IFFOM-Ventura Rate per MMBtu	$2.17	$1.96	$2.15	$2.18	$2.15	$1.92
8	Fuel Reimbursement - $	$6,794.27	$5,542.88	$6,731.65	$6,605.40	$6,731.65	$4,474.94
9	Firm Deferred Delivery - NNG						
10	Injection Volumes - MMBtus	0.0	0.0	0.0	0.0	0.0	62,490.0
11	Fuel Reimbursement %	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%
12	Fuel Gross-up - MMBtus	0.0	0.0	0.0	0.0	0.0	62,987.6
13	Fuel Reimbursement - MMBtus	0.0	0.0	0.0	0.0	0.0	497.6
14	IFFOM-Ventura Rate per MMBtu	$2.17	$1.96	$2.15	$2.18	$2.15	$1.92
15	Fuel Reimbursement - $	$0.00	$0.00	$0.00	$0.00	$0.00	$955.39

		July	August	September	October	November	December	Year
		(b)	(c)	(d)	(e)	(f)	(g)	(h)
16	Primary Firm Pipeline Capacity - NNG							
17	Monthly Receipts - MMBtus	155,000.0	155,000.0	150,000.0	155,000.0	150,000.0	155,000.0	1,825,000.0
18	Fuel Reimbursement %	1.53%	1.53%	1.53%	1.53%	1.27%	1.27%	1.67%
19	Fuel Gross-up - MMBtus	157,408.3	157,408.3	152,330.7	157,408.3	151,929.5	156,993.8	1,856,060.6
20	Fuel Reimbursement - MMBtus	2,408.3	2,408.3	2,330.7	2,408.3	1,929.5	1,993.8	31,060.6
21	IFFOM-Ventura Rate per MMBtu	$2.26	$1.84	$1.56	$1.92	$2.00	$2.13	$2.03
22	Fuel Reimbursement - $	$5,442.76	$4,431.27	$3,635.89	$4,623.94	$3,859.00	$4,246.79	$63,120.44
23	Firm Deferred Delivery - NNG							
24	Injection Volumes - MMBtus	75,564.0	43,064.0	52,080.0	64,793.0	0.0	0.0	297,991.0
25	Fuel Reimbursement %	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%	0.79%
26	Fuel Gross-up - MMBtus	76,165.7	43,406.9	52,494.7	65,308.9	0.0	0.0	300,363.8
27	Fuel Reimbursement - MMBtus	601.7	342.9	414.7	515.9	0.0	0.0	2,372.8
28	IFFOM-Ventura Rate per MMBtu	$2.26	$1.84	$1.56	$1.92	$2.00	$2.13	$1.93
29	Fuel Reimbursement - $	$1,359.84	$630.94	$646.	$990.53	$0.00	$0.00	$4,583.63

Volumes as it relates to Exhibit 4, TR 70

WARNER LINE BENEFIT TO
NORTHWESTERN UTILITY OPERATIONS

Exhibit___(TPH-5)

Additional Northern Natural Gas Firm Capacity Releases - MMBtus

Production Month	Capacity Release Credits-MMBtus	Production Month	Capacity Release Credits-MMBtus	Capacity Release Benefit-MMBtus
Nov. 96	629,293	Nov. 95	318,414	310,879
Dec. 96	808,811	Dec. 95	253,746	555,065
Jan. 97	803,188	Jan. 96	600,117	203,071
Feb. 97	792,730	Feb. 96	227,264	565,466
Mar. 97	734,515	Mar. 96	375,063	359,452
Apr. 97	742,858	Apr. 96	315,749	427,109
May 97	574,036	May 96	584,466	(10,430)
Jun. 97	518,238	Jun. 96	388,568	129,670
Jul. 97	679,555	Jul. 96	498,731	180,824
Aug. 97	334,683	Aug. 96	336,411	(1,728)
Sep. 97	167,725	Sep. 96	715,244	(547,519)
Oct. 97	590,645	Oct. 96	850,334	(259,689)
Totals	7,376,277	Totals	5,464,107	1,912,170

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Contract between NNG and NEC, TR98

ENRON
Northern Natural Gas Company

February 6, 1997

Mr. Tom Hitchcock
Northwestern Energy Corporation
600 Market Street West
Huron, South Dakota 57350-1318

Dear Tom:

Pursuant to our discussions, this Letter Agreement reflects commitments made by Northern Natural Gas Company ("Northern") and Northwestern Energy Corporation ("NEC").

Northern and NEC agree as follows:

1. NEC agrees to enter into a Firm Deferred Delivery ("FDD") Service Agreement for 300,000 MMBtu/cycle per year at Northern's maximum FDD storage services rates pursuant to Northern's FERC Gas Tariff, as amended from time to time ("Northern's Tariff"). Subject to the terms and conditions of Northern's Tariff, the term of the FDD Service Agreement will commence on June 1, 1997 and continue through May 31, 2002.

2. i) NEC agrees to enter into a twelve month firm Throughput Service Agreement for 5,000 MMBtu/day for a term commencing on June 1, 1997 and continuing through May 31, 2002.

   ii) The base reservation fee will be equal to $3.00/MMBtu for the months of April through October, and the base reservation fee will be equal to $3.50/MMBtu for the months of November through March, and a commodity rate equal to the maximum rate provided in Northern's Tariff. In addition to the above rates NEC shall pay the applicable ACA surcharge, any applicable GRI surcharge, and any other FERC approved demand and/or commodity surcharges. In addition to the above rates, NEC shall also pay any applicable fuel use and unaccounted for. NEC further agrees that the discount will only apply to the primary delivery point(s), including gas delivered into Northern's storage. If NEC utilizes any alternate delivery points the discount set forth herein will not be applicable and Northern's maximum rates will apply during the month that any alternate delivery points are utilized.

   iii) In no event shall the rates exceed the maximum rate or be less than the minimum rate authorized under Northern's Tariff. In the event the rates agreed to pursuant hereto are or become greater than the maximum or less than the minimum under Northern's Tariff, then NEC agrees that Northern will immediately decrease the rate(s) herein down to the maximum or increase the rate(s) herein up to the minimum.

iv) In the event that Northern implements an alternative rate design different from that existing as of the date hereof or Northern's maximum tariff rate is reduced from that existing as of the date hereof, the reservation fee and commodity rate(s) shall be adjusted to achieve the same economic value to both parties.

v) If it is determined, as a result of any decision or regulation issued by the FERC or other administrative agency or a court of competent jurisdiction (i) that any discount provided to NEC by Northern would, in effect, require Northern to provide similar discounts to other shippers, or that the providing of such discounted rates to NEC provides NEC an undue preference, (ii) that Northern is required to allocate costs to the service provided hereunder in excess of the discounted rates provided for herein, or recognize revenue as if it were charging rates in excess of the discounted rates provided for herein, then Northern shall immediately notify NEC of any such determination, and if NEC is not already paying the then effective maximum transportation rates, the maximum reservation fee and maximum commodity rates(s) provided for in Northern's then effective FERC Gas Tariff, as revised from time to time, shall be paid by NEC effective five (5) days after the date of said notice. In such event, NEC may terminate this Agreement upon ten (10) days' prior written notice to Northern from the date of Northern's notification to NEC.

vi) The primary receipt point shall be Ogden, IA (POI: 98) and the primary delivery points will be as specified in Appendix A.

vii) For service during the summer months of April through October, upon providing at least thirty (30) days advance written notice to NEC, but no later than July 1 of each year, Northern shall have the unilateral right to reduce or terminate the discount applicable to the firm throughput service agreement. In such event, NEC shall have the option to notify Northern within ten (10) days of the above notice from Northern, to terminate the firm Throughput Service Agreement to avoid paying the increased transportation fees.

viii) For service during the winter months of November through March, upon providing advance written notice to NEC by July 1 which precedes the November service, Northern shall have the unilateral right to reduce or terminate the discount applicable to the firm throughput service agreement. In such event, NEC shall have the option to notify Northern within ten (10) days of the above notice from Northern, to terminate the firm Throughput Service Agreement to avoid paying the increased transportation fees.

3. Each party agrees that it will maintain this Letter Agreement, all of its contents and subsequent documentation and communications in strict confidence and that it will not cause or permit disclosure thereof to any third party without the express written consent of the other party except to the extent necessary to comply with valid laws, regulations or orders of any court or agency having jurisdiction. However, in the event a party becomes aware of a judicial or administrative proceeding or request that has resulted or that may result in such disclosure, it shall so notify the other party immediately and will also take all actions necessary to maintain the confidentiality of all communications and documents.

If this Letter Agreement accurately represents your understanding of terms agreed upon, please so indicate by signing below.

Sincerely,

Michael W. McGowan
Vice President, Transportation Marketing

Accepted and Agreed to this 14th day of February, 1997.

NORTHWESTERN ENERGY CORPORATION

By:

TPH

APPENDIX A

FIRM THROUGHPUT SERVICE AGREEMENT, TFX RATE SCHEDULE

Shipper: Northwestern Energy Corporation

Contract Volume: 5,000 MMBtu/day

RP/DP Type	POI	Point Description	Jan/Dec
RP	98	Ogden	5,000
		TOTAL RECEIPTS:	5,000
DP	4086	Brookings	2,000
DP	4096	Huron	1,500
DP	4107	Volga	1,500
		TOTAL DELIVERIES:	5,000

Contract between NEC and NPS, TR99

ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT

This ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT ("Agreement") is made and entered this 30th day of October, 1996, to be effective November 1, 1996, by and between NORTHWESTERN ENERGY CORPORATION, a South Dakota corporation, herein referred to as "Seller", and NORTHWESTERN PUBLIC SERVICE COMPANY, a Delaware corporation, hereinafter referred to as "Buyer."

WITNESSETH THAT:

WHEREAS, Seller has purchased transportation capacity on the Warner pipeline from Nekota Resources, Inc., with such pipeline extending from an interconnection on the Northern Border Pipeline south of Aberdeen to the Aberdeen city-gate of Buyer; and

WHEREAS, Buyer has the desire to have competitive retail natural gas rates in South Dakota and to obtain the services of Seller to deliver a competitively priced upstream pipeline transportation capacity for delivery of natural gas to Buyer's distribution system in Aberdeen.

NOW, THEREFORE, in consideration of the premises, the mutual convenants and agreements herein contained, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, Seller and Buyer do hereby agree as follows:

I. QUANTITY

A. Seller agrees to receive from Buyer for transportation on a firm basis quantities of natural gas tendered by Buyer on any day at the Primary Receipt Point(s), and Seller agrees to transport and deliver to Buyer at the Delivery Point(s) up to the MDQ in accordance with the terms and conditions set forth in this Agreement.

B. The Maximum Daily Quantity ("MDQ") shall be 15,000 Dekatherms per day at the Delivery Point(s), subject to any adjustment allowed under this Agreement.

C. Subject to and conditioned upon gas and transportation capacity being available to Seller, Seller will exercise due diligence and good faith to provide transportation overrun service (i.e. a quantity of gas in excess of the MDQ) to Buyer on a reasonable efforts basis at the rate set forth in Article II, A.

II. **PRICE:**

A. Monthly Demand Charge: Buyer shall remit to Seller each month a Monthly Demand Charge equal to the higher of $3.20 times the total MDQ or fifty-five (55) percent of NPS' weighted average monthly Northern Natural Gas TF (Market Firm) capacity costs, at maximum FERC approved base rates. The determination of the calculation of such weighted average monthly rate, to be effective November 1, 1996, is shown on Appendix B to this Agreement. If Buyer exceeds the MDQ on any given day, the transportation overrun Dekatherms will be billed at the then applicable 100% load factor demand rate.

III. **DELIVERY POINTS:**

A. The Delivery Points(s) shall be the points of interconnection between the facilities of the Warner pipeline of Nekota Resources, Inc. and Buyer at Buyer's town border station in Aberdeen, South Dakota.

IV. **TERM:**

A. The term of this Agreement shall be ten (1) years commencing on November 1, 1996 and ending on October 31, 2006, subject to the other provisions of the Agreement.

V. **GENERAL TERMS AND CONDITIONS:**

The sale of transportation capacity hereunder shall be subject to the General Terms and Conditions attached hereto as Appendix A and made a part hereof. In the event of a conflict between the foregoing provisions of this Agreement and the following General Terms and Conditions attached hereto as Appendix A, the foregoing provisions shall govern.

IN WITNESS WHEREOF, each said parties has caused this Agreement to be executed in its corporate name and its corporate seal to be affixed and witnessed by its officers thereto duly authorized, the Day and Year first above written.

"SELLER"

ATTEST:
NORTHWESTERN ENERGY CORPORATION

By: _____ By: Thomas P. Hitchcock

Title: Secretary Name: Thomas P. Hitchcock

Title: Executive Vice President

"BUYER"

ATTEST:
COMPANY
NORTHWESTERN PUBLIC SERVICE

By: _____ By: _____

Title: Corporate Secretary Name: Arthur R. Donnell

Title: Vice President - Operations

APPENDIX A
ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT

GENERAL TERMS AND CONDITIONS

ARTICLE I
DEFINITIONS

A. For the purpose of this Agreement the following definitions shall apply:

1. "BTU" (British Thermal Unit") is the amount of energy required to increase the temperature of one (1) pound of water one (1) degree Fahrenheit at fifty-nine (59) degrees Fahrenheit.

2. "Contract Year" is a period of twelve (12) consecutive Months commencing and ending at 9:00 o'clock a.m. Central Clock Time on November 1 unless otherwise agreed.

3. "Cubic Foot of Gas" is the amount of gas necessary to fill one cubic foot of space when the gas is at a temperature of sixty (60) degrees Fahrenheit and under an absolute pressure of fourteen and seventy-three hundredths (14.73) pounds per square inch.

4. "Day" is a period of twenty-four (24) consecutive hours beginning and ending at nine (9) o'clock a.m. Central Clock Time ("CCT") or at such other time as Buyer and Seller may agree upon.

5. "Delivery Point(s)" is the point or points designated in this Agreement where Seller's supply is sold and purchased hereunder and delivered to Buyer. title to and possession of Seller's supply passes from Seller to Buyer at such point(s).

6. "Gas" or "Natural Gas" is any mixture of hydrocarbons or of hydrocarbons and non-combustible gas, in a gaseous state, consisting essentially of methane; or all merchantable gases that conform to the quality specifications of the Transporting Pipeline.

7. "Total Dry Heating Value" is the number of Btus produced by complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of 1 cubic foot at a temperature of 60 degrees Fahrenheit on a water-free basis and at a pressure of 14.73 p.s.i.a. with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has condensed to the liquid state.

8. "Dekatherms" is one million (1,000,000) British thermal units.

9. "Month" is a period beginning at 9:00 o'clock a.m. Central Clock Time, or at such other time as the parties have agreed upon, on the first Day of the calendar Month and ending at the same time on the first Day of the next calendar Month.

10. "Monthly Billing Period" is the calendar Month.

11. "Party" is Buyer or Seller.

12. "Parties" is Buyer or Seller.

13. "PSI" is the pressure measured in pounds per square inch.

14. "p.s.i.a." is pound per square inch absolute.

15. "p.s.i.g." is pound per square inch gauge.

16. "Quantity" when used to refer to a quantity of gas shall mean the Total Energy Content.

17. "Total Energy Content" is that amount determined by multiplying the total dry heating value by the volume of gas in cubic feet.

18. "Transporting Pipeline" is any pipeline providing transportation or storage service prior to Buyer's distribution system.

ARTICLE II
WARRANTY AND TITLE

A. Seller warrants, at the time of delivery, Seller's title to, and its rights to sell, the gas delivered hereunder, and warrants that such gas is free from liens, encumbrances, and adverse claims. Seller agrees to indemnify Buyer against any direct loss, damage, or expense which Buyer may sustain from a claim involving gas sold or delivered hereunder prior to delivery into the Buyer's distribution system. Buyer agrees to indemnify Seller against any direct loss, damage or expense which Seller may sustain from a claim involving gas sold or delivered hereunder after delivery into the Buyer's distribution system. Neither party shall be liable to the other for indirect, consequential, or special damages related to this Agreement.

ARTICLE III
TAXES

A. Seller shall pay or cause to be paid all taxes lawfully levied on Seller applicable to the gas sold hereunder prior to delivery into the Buyer's distribution system. Buyer shall pay or cause to be paid all taxes lawfully levied on Buyer applicable to the gas sold hereunder after delivery into the Buyer's distribution system. Absent Seller's receipt from Buyer of an appropriate sales tax exemption certificate, Buyer shall be obligated to remit to Seller, and Seller shall be entitled to collect from Buyer, any applicable state sales tax levied on the sale of gas under this Agreement.

ARTICLE IV
QUALITY & MEASUREMENT

A. All gas delivered hereunder shall meet the quality specifications of the Transporting Pipeline and shall be measured by and in accordance with the measurement requirements of the Transporting Pipeline, unless the gas delivered by Seller hereunder was nevertheless accepted by the Transporting Pipeline and the gas that was actually delivered to Buyer's TBS met the written quality specifications set forth in the Transportation Pipeline's tariff.

ARTICLE V
IMBALANCE PENALTIES

A. The parties recognize that Buyer will be liable for any reasonable charges and penalties imposed by the Transporting Pipeline for imbalances or variances in deliveries. Seller agrees to act in good faith and with due diligence to avoid any such charges or penalties, and to cooperate in a timely fashion to adjust gas forecasts, nominations and/or deliveries as necessary to bring deliveries and receipts into balance to the extent that penalties are avoided or minimized as much as possible.

ARTICLE VI
BILLING AND PAYMENT

A. Seller shall use reasonable efforts to render invoices on or before the fifteenth (15th) Day of each Month for the Monthly Demand Charge applicable to the current Month. Invoices shall also reflect any applicable adjustments from prior Months. When information necessary for billing purposes is in the control of Buyer, such information relating to the prior Month shall be delivered to Seller by Buyer on or before the fifth (5) business Day of each Month.

B. Buyer shall pay Seller by wire transfer to the place and account designated by Seller in the Agreement:

1. On or before the twenty-fifth (25) Day of each Month all charges reflected on the invoice rendered by Seller in the current Month pursuant to Paragraph A of this Article; provided, however, that payment shall never be due until ten (10) Days after the receipt of the Seller's invoice; and

2. Any adjustments or additional payments shall be paid with the next following month's invoice.

C. Any invoiced amount due Seller under this Agreement not paid when due shall bear interest calculated at the daily equivalent of the Prime Rate plus two (2%) percent per annum. "Prime Rate" shall mean the per annum rate of interest for established commercial customers published from time to time by Norwest Bank South Dakota, N.A.

D. Any payments received from Buyer shall first be applied to any accrued interest due, then to the principal portion of any overdue charges, and lastly to the principal portion of any charges currently due.

E. Seller and Buyer shall each have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge or computation made under or pursuant to any of the provisions hereof.

ARTICLE VII
FORCE MAJEURE

A. The term "force majeure" shall mean acts of God; earthquakes, landslides, lightning, fires, storms, floods, washouts, freezing of wells or pipelines, explosions, rupture of lines of pipe, breakage of or accident to machinery, wells, gathering lines, pipelines, compressors or plants or any other interdicting, physical event; strikes, lockouts, or other industrial disturbances; or wars, riots, civil disturbances, or insurrections; regulation or order of a governmental agency limiting access to gas supply; partial or entire failure of gas supply over which Seller has not control; failure or inability of Transporting Pipeline(s) to transport gas; inclement weather that necessitates extraordinary measures and expense to construct facilities and/or maintain operations; acts of governmental authorities having jurisdiction (including, but not limited to, federal, state, or municipal entities) which render either party unable to legally carry out their obligations, or which significantly impact a party's ability to meet its commitments under this Agreement, excepting any governmental acts made at the request of the party

claiming force majeure; or any other cause or causes beyond reasonable control of the party, whether of the kind enumerated or otherwise; provided, however, that none of the foregoing shall constitute an event of force majeure unless it is not reasonably within the control of the party claiming the occurrence thereof. Neither party shall be entitled to claim economic force majeure with respect to any agreed upon price for the sale or purchase of any services or supply under this Agreement.

B. If either Seller or Buyer is rendered unable by the occurrence of an event of force majeure to carry out in whole or in part its obligations hereunder, the obligations to make demand charge payments and payments for services performed or supplies actually delivered, shall be suspended during the continuance and to the extent of any inability so caused but for no longer period, and such cause shall, so far as possible, be remedied with all reasonable dispatch. An event of force majeure shall not, however, relieve a party of liability in the event or its concurring negligence or for any period during which it fails to use reasonable diligence to remedy the situation and remove the cause in an adequate manner and with all reasonable dispatch; nor shall the event relieve a party of liability under any circumstances unless the party gives notice and full particulars of the same in writing or by facsimile to the other party as soon as possible after the occurrence. The foregoing notwithstanding, nothing herein shall require either party to settle a strike against its will.

C. This Agreement shall not be terminated by reason of any suspension of obligations hereunder due to the occurrence of an event of force majeure.

ARTICLE VIII
ASSIGNMENT

A. Seller may assign, or grant a security interest in, any or all its rights to or in respect of payments made or to be made (or due or to become due) under this Agreement. This Agreement may not otherwise be assigned by either party without the written consent of the other party, which consent shall not be unreasonably withheld. Each successor to Seller and Buyer shall be bound by this Agreement.

ARTICLE IX
MISCELLANEOUS

A. Waiver. No waiver by Buyer or Seller of anyone or more defaults by the other in its performance under any provision hereof shall operate or be constructed as a waiver of any future default or defaults, whether of a like or different character. No delay, short of the statutory period of limitation, in asserting or enforcing any right hereunder shall be deemed a waiver of or limitation on such right.

B. Amendment. Any change in the provisions of this Agreement made subsequent to the date of execution hereof shall not be binding unless made by executed, written amendment, and no course of dealing or course of performance between the parties, or trade usage, shall be considered in determining the meaning and intent of the terms and conditions stated herein.

C. Third-Party Beneficiaries. Except as a result of an assignment permitted herein, this Agreement shall not give rise to any rights in any person not a signatory party hereto. In particular, no person shall be entitled to claim the status of a third-party beneficiary with respect to or on account of any provision of this Agreement.

D. Headings. The descriptive headings for the articles and sections contained in this Agreement are for convenience only and shall not be considered to affect the meaning or interpretation of the provisions herein.

E. Notices and Communications. All notices or communications required by this Agreement to be given to a party in writing shall be addressed as follows:

If to Buyer:

Northwestern Public Service Company
33 Third Street SE
P. O. Box 1318
Huron, SD 57350-1318
Attention: Vice President, Energy Operations
Phone: (605) 352-8411 Facsimile: (605) 353-8286

If to Seller

Northwestern Energy Corporation
33 Third Street SE
P. O. Box 1318
Huron, SD 57350-1318
Attention: Executive Vice President
Phone: (605) 353-8235 Facsimile: (605) 353-8216

All payments by Buyer and Seller shall be wire transferred to:

Wire transfer information for Seller:

Norwest Bank, Huron Office, N.A.
ABA #
Acct: Northwestern Energy Corporation
Acct # 1800015237

Any party may change the address to which notices, communications, or payments are to be sent by giving the other party written notice of such change in the manner provided for by this section. Receipt or notices, communications or invoices shall be deemed effective when received if sent by U.S. mail or date faxed or date placed with overnight delivery service unless otherwise provided for in this Agreement.

F. Applicable law. The parties' rights and obligations hereunder shall be interpreted in accordance with the laws of the State of South Dakota, except for any doctrine or provision thereof that would direct the application of the laws of another state. Any legal action under this Agreement must be brought before a court in the State of South Dakota.

APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
Northwestern Public Service Company and
Northwestern Energy Corporation

Original

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	Northwestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective Nov. 1, 1996				
TF -12 Base	$5.6710	12,992	12	$73,677.63
TF -12 Variable	$6.8050	19,297	12	$131,316.09
TF-5	$11.3420	16,994	5	$80,310.81
	$5.7891	49,283		$285,304.53
55% of Weighted Rate per MDQ	$3.1840			
Higher of Above Rate or $3.2000	$3.2000			
Overrun Rate (100% LF)	$0.1052			

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APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
Northwestern Public Service Company and
Northwestern Energy Corporation

Revision No. 1

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	Northwestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective Nov. 1, 1997				
TF -12 Base	$5.6710	11,437	12	$64,859.23
TF -12 Variable	$6.8050	20,465	12	$139,264.33
TF-5	$11.3420	20,313	5	$95,995.85
	$5.7478	52,215		$300,119.41
55% of Weighted Rate per MDQ	$3.1613			
Higher of Above Rate or $3.2000	$3.2000			
Overrun Rate (100% LF)	$0.1052			

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APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
Northwestern Public Service Company and
Northwestern Energy Corporation

Revision No. 2

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	Northwestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective Nov. 1, 1998 (@ Settlement Rates in RP98-203)				
TF -12 Base	$6.6560	9,589	12	$63,824.38
TF -12 Variable	$7.9870	22,313	12	$178,213.93
TF-5	$13.3120	20,313	5	$112,669.44
	$6.7932	52,215		$354,707.75
55% of Weighted Rate per MDQ	$3.7363			
Higher of Above Rate or $3.2000	$3.7363			
Overrun Rate (100% LF)	$0.1228			

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APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
Northwestern Public Service Company and
Northwestern Energy Corporation

Revision No. 3

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	Northwestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective Dec. 1, 1998 (@ Settlement Rates in RP98-203)				
TF -12 Base	$5.6710	9,589	12	$54,379.22
TF -12 Variable	$6.8050	22,313	12	$151,839.97
TF-5	$11.3420	20,313	5	$95,995.85
	$5.7879	52,215		$302,215.04
55% of Weighted Rate per MDQ	$3.1833			
Higher of Above Rate or $3.2000	$3.2000			
Overrun Rate (100% LF)	$0.1052			

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APPENDIX B
FIRM ABERDEEN CITY-GATE TRANSPORTATION SERVICES AGREEMENT
Between
Northwestern Public Service Company and
Northwestern Energy Corporation

Revision No. 4

NNG TF Rate Schedule	NNG Maximum Base Rate Per Dekatherm	Northwestern Public Service MDQ with NNG Dekatherms	Months of MDQ	Weighted $
Rates and MDQ Effective Nov. 1, 1999 (@ Settlement Rates in RP98-203)				
TF -12 Base	$4.4980	9,589	7	$25,159.94
	$8.0960	9,589	5	$32,346.89
TF -12 Variable	$4.4980	22,313	7	$58,545.59
	$10.9750	22,313	5	$102,035.49
TF-5	$11.9940	20,313	5	$101,514.22
	$6.1209	52,215		$319,602.13
55% of Weighted Rate per MDQ	$3.3665			
Higher of Above Rate or $3.2000	$3.3665			
Overrun Rate (100% LF)	$0.1107			

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Franklin R. Bay
Vice President
Business Development & Marketing

Enron Transportation
& Storage
Services Provided by Northern
Natural Gas Company and
Transwestern Pipeline Company

P. O. Box 3330
Omaha, NE 68124-0330
(402) 398-7030
Fax (402) 398-7413
fbay@enron.com

October 30, 1998

Margaret Corcis
Northwestern Public Services
605/353-8346

Dear Margaret:

As you are aware, on November 1 of each year the maximum quantity available for each shipper's TF12 Base is redetermined based on shipper's actual average daily deliveries to the town border stations or delivery points listed in the shipper's TF and TI Service Agreements (Section 9 of the TF Schedule). In accordance with Northern's tariff, attached please find the preliminary Throughput Entitlement Profile reflecting the reallocated TF12 Base and TF12 Variable entitlement effective November 1, 1998. Northern is in the process of finalizing these numbers and will notify you of any change by November 13, 1998. The final volume will be utilized for billing the November 1998 volumes.

If you have any questions, please contact your account representative.

Sincerely,

Franklin R. Bay

30-Oct-98

NORTHERN NATURAL GAS COMPANY
EFFECTIVE NOVEMBER 1, 1998
THROUGHPUT ENTITLEMENT PROFILE

Transportation Marketing
Marketing Analysis

UTILITY: NORTHWESTERN PUBLIC SERVICE
CODE: 440

Actual May Through September 1998 Throughput (MMBtu)

ACCT MO	GS	TF	TI	FDD/IDD	OTHER	TOTAL
MAY		181,357		10,621		191,978
JUN		208,502		124,800		333,402
JUL		200,330		182,080		382,410
AUG		159,924		109,039		264,963
SEP		205,427		118,900		324,327
TOTAL:	0	954,540	0	812,527	0	1,497,087
					average day	9,589

APPROVED TFX:	5,000
APPROVED TF5:	20,313
APPROVED TF12:	31,902
TOTAL:	57,215

ALLOCATED TF12I:	9,589
ALLOCATED TF12V:	22,313
TOTAL:	31,902

CONTRACT	TFX ENTLMNT	TF5 ENTLMNT	TF12V ENTLMNT	TF12I ENTLMNT	TOTAL ENTLMNT	TFF ENTLMNT	GST ENTLMNT
21374	0	20,313	22,313	9,589	52,215	22,500	0
102944	5,000				5,000		
TOTAL:	5,000	20,313	22,313	9,589	57,215	22,500	0



South Dakota Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

January 21, 2000

Mr. William Bullard, Jr.
Executive Director
SD Public Utilities Commission
500 E. Capitol Building
Pierre, SD 57501

RE: NG99-002

Please be advised that Commission Staff will not be filing additional comments on the late filed exhibits in the above referenced matter. The exhibits were not timely filed and therefore it is inappropriate for the Commission to consider them at this time.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

cc: Russell C. Molstad, Jr.
David Jacobson
Robert Towers

Capitol Office
Telephone (605)773-3201
FAX (605)773-3809

Transportation/
Warehouse Division
Telephone (605)773-5280
FAX (605)773-3225

Consumer Hotline
1-800-332-1782

TTY Through
Relay South Dakota
1-800-877-1113

Internet Website
www.puc.state.sd.us/puc/

Jim Burg
Chairman
Pam Nelson
Vice-Chairman
Laska Schoenfelder
Commissioner

William Bullard Jr.
Executive Director

Harlan Best
Martin C. Bettmann
Sue Cichos
Karen E. Cremer
Terry Emerson
Michele M. Farris
Marlette Fischbach
Heather K. Forney
Shirleen Fugitt
Mary Giddings
Lewis Hammond
Leni Healy
Camron Hoseck
Lisa Hull
Dave Jacobson
Bob Knadle
Delaine Kolbo
Charlene Lund
Gregory A. Rislov
Keith Senger
Rolayne Ailts Wiest

NorthWestern
PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney
605-353-7504
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January 21, 2000

RECEIVED
JAN 24 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard
Executive Director
SD Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

Re: Docket No. NG99-002
Rebuttal Brief of NorthWestern Public Service

Dear Mr. Bullard,

I am enclosing the original and ten copies of NorthWestern's Rebuttal Brief in Docket NG99-002 for filing in this matter.

If you have any questions, please feel free to contact me.

Sincerely,

Russell C. Molstad, Jr.
Corporate Attorney

ss
enclosures
cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker

NorthWestern
PUBLIC SERVICE

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January 21, 2000

Ms Karen Cremer
S.D. Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070

RECEIVED
JAN 24 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Re: Docket No. NG99-002
Rebuttal Brief of NorthWestern Public Service

Dear Karen,

I m enclosing a copy of NorthWestern's Rebuttal Brief in above entitled matter. I have filed the original and ten copies with Mr. Bullard.

If you have any questions, please feel free to contact me.

Sincerely,

Russell C. Molstad, Jr.

Russell C. Molstad, Jr.
Corporate Attorney

ss
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cc: Alan Dietrich
Tom Hitchcock
Rod Leyendecker

RECEIVED
JAN 24 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	**DOCKET NO. NG 99-002** **REBUTTAL BRIEF OF NORTHWESTERN PUBLIC SERVICE**

INTRODUCTORY STATEMENT

In this Rebuttal Brief relevant parties will be referred to as follows: NorthWestern Public Service, a division of NorthWestern Corporation will be referred to as "NorthWestern"; the South Dakota Public Utilities Commission will be referred to as the "Commission"; and the Staff of the Commission will be referred to as the "Staff". Other entities that will be referred to in this brief include: NorthWestern Energy Corporation, a wholly owned subsidiary of NorthWestern Corporation, which will be referred to as "NEC"; Nekota Resources, Inc., a wholly owned subsidiary of NEC, which will be referred to as "Nekota"; Northern Natural Gas Company, an unrelated interstate pipeline company, which will be referred to as "NNG"; and Northern Border Pipeline Company, an unrelated interstate pipeline company, will be referred to as "NBPL". References to the transcript of the hearing held on October 20, 1999, will be by page number as follows: (TR__). Exhibits admitted at the hearing will be referred to by exhibit letter or number as follows: (Exh___).

NorthWestern relies on its recitation of the facts in the Abstract of Evidence in its Initial Brief. NorthWestern will not reiterate the facts of this case unless it is necessary to the understanding of the issues.

ARGUMENT AND AUTHORITY
ISSUE ONE

The charges for capacity on the Nekota Pipeline included by NorthWestern in its PGA filings are just and reasonable and consistent with NorthWestern's adjustment clause.

Staff in its Brief would like to limit NorthWestern's recovery to the construction costs of the Nekota Pipeline of $1,185,000. Staff cites SDCL 49-34A-25 as authority for its position. The statute allows an automatic adjustment of charges that are in direct relation to the delivered cost of gas. This statute does not confine purchased gas adjustment recovery costs to construction costs. If the statute was intended to cover only construction costs, and not other costs of the project, it could have stated that in the statute. Instead the statute states that delivered costs of gas can be recovered through the purchased gas adjustment clause. The question for determination is what were the costs of the Nekota Pipeline project.

Commission Staff would like to characterize the costs set forth in (Exh. 3) as "creative". The method used to construct the pipeline was a creative response to an immediate and complex problem. However, the costs incurred in completing the project were real. As the record indicates, through the testimony of Tom Hitchcock, the $568,000 paid by NEC to NNG was an indispensable cost of the project. As Mr. Hitchcock testified, NorthWestern had a contractual obligation with NNG whereby NNG was NorthWestern's exclusive pipeline facility in South Dakota (TR 26-7; Exh. 2). As unpleasant as it was to NorthWestern at the time, the $588,000 was one of the terms insisted upon by NNG to help them recover some of their revenues due to the proposed by-pass Aberdeen pipeline. It was not creative, it was not blue sky, it was absolutely necessary in order for the project to happen. There is nothing in the record that would contradict this undisputed fact. The $588,000 paid by NEC for 5,000 MMbtu of capacity, along with the administrative costs, pre-tax return, property taxes and construction costs all constituted parts of the total project costs. All of the costs were "directly related" and

part of the delivered cost of gas to Aberdeen. Therefore, under SDCL 49-34A-25 these are properly recovered under the purchase gas adjustment filing.

Staff in its footnote on page 3 of its Brief, states that NorthWestern did not explain why 70% of the project costs were assigned to NorthWestern, when its contract with NEC assigns to it only 15,000 MMbtu, or 62.5% of the pipeline's 24,000 MMbtu/day capacity. The record does not support Staff's position. NorthWestern did explain the percentages and the assignment of project costs at the hearing (TR 56-57 (Exh. 3). NorthWestern has the right to use 100% of the Nekota pipeline's 24,000 MMbtu capacity. The total capacity assigned for the project includes 15,000 MMbtu for NorthWestern on the Nekota Pipeline for Aberdeen, 1,500 MMbtu for NEC on the Nekota Pipeline, if not required by NorthWestern, and 5,000 MMbtu for NEC on the NNG pipeline. The total capacity for the project was 21,500 MMbtu. The 70% share in the cost was arrived by dividing NorthWestern's 15,000 MMbtu by the total MMbtu for this project of 21,500, or 70%. This 70% allocation included all aspects of this project, including the 5,000 MMbtu in transportation services purchased by NEC from NNG for $588,000. Finally, per its contract with NEC, NorthWestern can overrun its assigned capacity on the Nekota Pipeline, up to the pipeline's capacity of 24,000 MMbtu, for a minimal fee for that is far less than it would have had to pay NNG for the same capacity (TR 44).

Staff takes the position that the $576,000 being charged to ratepayers is excessive. A quick review of the facts of this case does support that position. NorthWestern is only passing on those costs that were necessary for the construction and NorthWestern's ability to utilize the pipeline. Commission Staff has taken a very narrow approach on this issue, and seeks to limit the Commission's consideration to the actual construction costs of the pipeline. Staff Witness Jacobson admitted at the hearing that he failed to take into consideration in making his recommendation on this issue the many additional benefits to NorthWestern customers that came from this project. I think it is important to outline these benefits again:

(a) NorthWestern's right to use the Aberdeen capacity elsewhere on its system (TR 149);

(b) The improvements to allow NorthWestern to meet its peak day capacity (TR 149-150);

(c) The elimination of the pressure problem at Aberdeen (TR 150);

(d) The ability of NorthWestern to reassign its delivery point capacity throughout its system on NNG, and the ability to avoid point-to-point penalty charges (TR 150);

(e) The exchange of essentially valueless field capacity for 7,000 MMbtu of valuable market area capacity (TR 62, 63, 150); and

(f) The ability to increase margins for NorthWestern by having increased potential sales to interruptible customers through sales of capacity released (TR 151).

In addition to the benefits listed above, significant monetary benefits were received by NorthWestern's customers as a result of this project. If NorthWestern had continued to receive firm capacity from NNG instead of constructing the pipeline, it would have paid 1.2 million instead of $576,000 annually for such capacity (TR 36-37; Exh 3). In addition it would have remained obligated to NNG for its exclusive transportation of natural gas (leaving it less options for the future needs of the its system). Furthermore, NorthWestern would not have solved the other problems on its system including operational concerns, less valued fuel capacity, and delivery point capacity that was not aligned with its needs.

It should be noted that this entire project and the resulting purchased gas adjustment costs were the result of NorthWestern's attempt to get competitively-priced pipeline capacity to meet the needs of not only NorthWestern's residential and business customers, but also the agency customers of NorthWestern. NorthWestern needed to acquire additional firm capacity to protect its high priority customers from a potential disruption of service. Commission Staff in its brief argues that NorthWestern's rate of return is unreasonable because it did not seek other bids for a comparable pipeline built and owned by others. First of all, Tom Hitchcock testified

that NorthWestern was familiar with the cost of constructing a pipeline and that it had a good history with the company that was going to construct the pipeline. He further testified that the costs of the Aberdeen pipeline based upon their history and knowledge were very reasonable (TR 66-67). NorthWestern chose not to litigate the "exclusivity" provision of its contract with NNG. That course of action was fraught with large costs, long delays and an uncertain result. Therefore, contrary to Staff's position, NorthWestern did review all of its options, and the costs being paid to NNG prior to the construction on the pipeline. It is easy to second guess and criticize the review process used by NorthWestern; however, one is hard pressed to criticize the benefits to NorthWestern's customers generated as the result of the pipeline.

Staff cites the case Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electrical Services as support for its position that NorthWestern's cost were unreasonable. First of all, as alluded to in NorthWestern's Initial Brief, this case specifically noted that a regulated rate of return could **not** be applied to an unregulated company. This is the case here. NEC's unregulated rate of return should not be set at Staff's proposed 8.53% regulated rate of return. Based on the reasonableness of the course of action taken by NorthWestern, and the cost ($3.20 compared to $6.25), NEC's 9.60% rate of return is not excessive. Importantly as outlined in the Montana-Dakota Utilities Co. case, and as recognized in Staff's brief, the Court said it was more concerned with the result than the method employed. The numerous benefits to NorthWestern's customers resulting from the construction of the pipeline have been discussed and outlined. If the result is the standard, then NorthWestern has unequivocally met that standard and NorthWestern's $576,000 share of the project is certainly reasonable and should be approved.

Commission Staff states in its brief that it is not possible to determine the basis for the $588,000 cost of this project. That is not the case. Mr. Hitchcock in his testimony and as set forth on (Exh. 3) testified that the $588,000 was paid by NEC for the purchase of 5,000 MMbtu of transportation and firm delivery service on NNG's pipeline. This portion of the entire project

cost was implemented in order for NNG to delete the clause in its contract with NorthWestern which made NNG the exclusive carrier of capacity for NorthWestern in South Dakota to provide better alignment of its capacity, and to turn back useless field capacity for valuable market capacity . The basis of the $588,000 was established. NorthWestern has filed the requested late-filed exhibits prior to the filing of this Rebuttal Brief. Commission Staff had the information in this late-filed exhibit explaining the basis for the $588,000 as an exhibit in the main rate case, but has chosen to ignore it and the testimony of Mr. Hitchcock at the hearing.

Staff in its brief objects to the admission of NorthWestern's late-filed exhibits. Staff did not bring to NorthWestern's attention that the exhibits had not been filed until it was noted in their brief. NorthWestern filed the exhibits immediately upon learning of the omission. NorthWestern apologizes for inadvertent delay in filing. However, there was no time limit set to file the exhibits. NorthWestern has agreed to allow Staff time to respond to the exhibits. Finally, Staff had the following exhibits during its review of the main case: (1) calculation of pre-tax return and (2) contract between NEC and NPS. No prejudice has resulted from this. Staff's position on this issue is without merit.

Commission Staff cites the case of Consumer Power Company v. Michigan Public Service Commission, et al., in support of the proposition even if the pipeline was necessary that all costs associated with the construction of the Nekota Pipeline were reasonable and prudent and capable of being passed on to the ratepayer. The facts of that case are not similar to the facts in this matter. In the Consumer Power Company case, the company entered in to a contract with one of its customers, James River, and it lost $1.5 million in revenue as a result of the special rate it gave to that company. In the present case, the result of the Nekota Pipeline project was to save the customers over $500,000 per year in capacity charges, an additional $200,000 per year savings as a result of additional capacity release credits, together with the previously listed benefits to NorthWestern's customers through improvements in the system itself. The PSC in the Consumer Power case put conditions on consumers as part of the

approval of the contract because of the 1.5 million dollar loss. Not only in the case before this Commission is there not a loss resulting in additional cost for the customers, but there are numerous benefits to customers both monetary and non-monetary.

Finally, Commission Staff argues in its Brief that SDCL 49-34A-25 deals only with errors found in the filing and does not allow the Commission Staff to assess the reasonableness of the commodity or the delivery costs and purchasing practices. However, a closer review of the statute demonstrates that this is exactly what this statute does, in fact, contemplate. The statute authorizes the Commission to require by order that the public utility file a bond or other security upon such terms and conditions as the Commission may require and for such purposes as contained in 49-34A-17 and 49-34A-22, if the *revised rate schedule is in error.* This statute is intended to address far more than Commission Staff's position that it deals only with filing errors, and not unreasonable rates.

Both sections 49-34A-17 and 49-34A-22 deal with the refund or credit of rates after they have been implemented and later found to be in some way unreasonable or inappropriate. SDCL 49-34A-17 deals with implementation of rates subject to refund. SDCL 49-34A-22 deals with the future rate reduction or credit as an alternative to refunds after a suspended schedule has been put into effect. In both cases, the statutes deal with the implementation of rates initially and either a refund or rate reduction or credit being implemented after the Commission reviewed the proposed rate increase. Therefore, it is abundantly clear that SDCL 49-34A-25 which is the basis for the purchased gas adjustment is intended as a statute to mandate that the Commission file objections to the revised rate schedule within ten days of the filing or they are deemed approved. If they file the order within ten days, the rates are implemented subject to the provisions of SDCL 49-34A-22 and SDCL 49-34A-25. If no order is entered, the filings are approved and not reviewable. The record is clear, that NorthWestern filed the purchased gas adjustment filings in this case from 1996 to the present. The record is also clear that the

Commission has not entered any order within any ten day period as required by the statute. Therefore, pursuant to this statute, the rate filings have been approved.

ISSUE TWO

The previously filed amended purchased gas adjustment clause filings made by NorthWestern are deemed approved by the Commission and are not subject to refund.

Commission Staff in its Brief tries to discredit NorthWestern by stating that the new purchased gas adjustment form filed by NorthWestern was coincidentally tied to this project. The record does not support those assertions. First of all, the change in the purchased gas adjustment form came as a result of a challenge by PAM Natural Gas to NorthWestern's purchased gas adjustment filing and rates in general (TR 45). Commission Docket NG96-015 resulted in a new stand alone purchased gas adjustment filing. Therefore, the new format was the result of a challenge by a third party and not done intentionally by NorthWestern as Staff would like the Commission to believe. Furthermore, as part of that docket, NorthWestern proposed and submitted to the Commission Staff in an exhibit the proposed new format that listed the Aberdeen pipeline project, which is the subject of this matter.

The Commission approved the Aberdeen pipeline rates in its December 1, 1996 Order (Exh. 6) following that hearing. The Nekota costs assigned to NorthWestern were included in proposed and approved work papers for the PGA true-up accounting in NG96-015, and these costs were incorporated into the tariff rates that were approved to be effective December 1, 1996 (TR 52). (See Exh. 6) NorthWestern admits that it could have been clearer in noting the Nekota Pipeline had been added to its purchased gas adjustment filings. However, the method of denoting the Aberdeen pipeline was the same as what has been used in all previous and subsequent filings for the individual charges. None of the other filings specify the supplier of the product or service (i.e. Nekota). It should be noted, however, that this was a new item, and therefore Commission Staff could have discovered a new purchased gas adjustment for an additional $576,000 and as, for the first time, Northern Border was attached to an Aberdeen

purchased gas adjustment cost. In any event, nothing will be accomplished by finger pointing in this matter. It was just an unfortunate lack of communication that has resulted in this issue coming before the Commission three years later. Both Staff and NorthWestern can and will do a better job in the future of explaining and identifying these costs. However, the fact of the matter is, there is no authority for the denial of the purchased gas adjustment just because Staff feels that there was insufficient notification or identification of the purchased gas adjustment costs in this filing.

Commission Staff relies on SDCL 49-34A-6 and 49-34A-26 as precedents for its position that the purchased gas adjustment cost filings are subject to refund. Both of these are statutes that generally set forth the powers of the Commission. Neither of those statutes deal with the specifics of a purchase gas adjustment filing. It should be noted that purchased gas adjustment filings are regulated by a specific statute, namely SDCL 49-34A-25. It is NorthWestern's position that this specific statute overrides any general powers that the other two statutes may give the Commission to cause a refund to be issued in this matter. It is a general rule of statutory construction that a specific statute overrides a general statute. Thomas v. McNeal, 444 N.W.2d 231, 237 (S.D. 1989). SDCL 49A-34A-25 addresses the specific purchase gas adjustment filings and therefore prevails over the general provisions of SDCL 49-34A-22. See also Meyerink v. NorthWestern Public Service, 391 N.W.2d 180, 184 (S.D. 1986). If the legislature had intended that purchased gas adjustment filings were subject to refund after approval at any time, the provisions of SDCL 49-34A-6 and 49-34A-26 would not have addressed the filings in a special statute. SDCL 49-34A-25 sets forth a procedure specific to purchased gas adjustments and gives them special automatic adjustment and rules to follow to object to the filings.

The purchased gas adjustment filings were initially approved by the Commission on December 1, 1996. Subsequent filings have been made in the exact same manner for the $576,000 amount which is the subject of this action on a monthly basis up to and including this

date. Upon Staff review and recommendation, the Commission under the statute could have filed an order requiring a bond within ten days of any one of the filings in order to give it the ample time to review the reasonableness of the charge and to subject the filing to refund, credit or other rate adjustment as set forth in that statute. The lack of any Commission action to enter an order in this matter leaves the rates approved pursuant to the statute. The Commission has adopted no rules dealing with PGA filings, and NorthWestern has tendered its filings in a manner consistent with the statute and its approved tariffs. Although NorthWestern believes the procedure gives adequate protection to the ratepayers, if a change by statute or rule should be made, it is a function of the legislature (statute) or the Commission (rule) to make those changes.

Commission Staff relies on the case of Northern Michigan Water Company v. Michigan Public Service Commission in support of its argument that the Commission can cause a refund in this matter. The facts of the Northern Michigan Water Company case are not in alignment with the facts of this case. First of all the Northern Michigan case was not a case involving a purchase gas adjustment. In the Northern Michigan Water Company case, the Water Company revised base rates without Commission approval. In the case before this Commission, the purchased gas adjustment tariffs allow for automatic increase subject to challenge. The purchased gas adjustment filings were not challenged by the Commission and therefore are approved.

CONCLUSION

In 1996 NorthWestern was faced with a number of challenges. In the best interests of its customers, it sought to meet those challenges by construction of a pipeline that was greatly beneficial to NorthWestern and its customers. The $576,000 in charges to NorthWestern recovered through the purchased gas adjustment charge by NorthWestern, are costs directly related to the project. Without the inclusion of all of those costs, the pipeline would not have been built and NorthWestern's customers would not have received the benefits that have been

set forth in NorthWestern as established in the record. Therefore, pursuant to statute, all of the charges are allowable through the purchased gas adjustment. The charges are not only allowable under the purchased gas adjustment statute, but they are fair and reasonable when compared to what NorthWestern's customers would have paid if the project would not have been completed.

In addition, there is no support either in law or fact to support Staff's request that NorthWestern's previously filed amended purchased gas adjustment clause filings be subject to refund. NorthWestern made the PGA filing that was approved by the Commission in December of 1996 and the same adjustment has been included in every monthly filing for three years in full compliance NorthWestern's PGA tariff, without any objection, suspension or order by the Staff or the Commission. There is no evidence to indicate NorthWestern did anything unlawful or improper. Furthermore, the evidence shows that the charges were filed in good faith by a company that was proud of what it had accomplished for its customers. Although lessons were learned by both NorthWestern and the Commission Staff regarding ways to make the filings more recognizable, and understandable, it does not make the previously filed amended purchased gas adjustment costs filings subject to refund. NorthWestern submits that the Commission should uphold NorthWestern's purchased gas adjustment and should adopt the findings submitted in NorthWestern's Initial Brief.[1]

Dated this 21st day of January, 2000.

Respectfully submitted,

NORTHWESTERN PUBLIC SERVICE

Russell C. Molstad, Jr.
Corporate Attorney

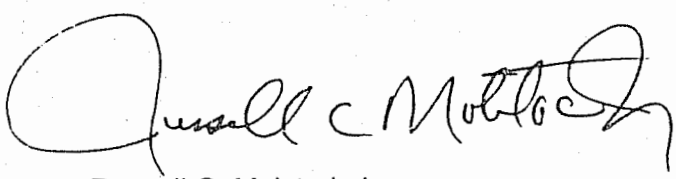
Alan D. Dietrich
Vice President - Legal Administration
NorthWestern Corporation

[1]NorthWestern notes that Staff has failed to submit proposed findings with its brief, as required by ARSD 20:10:01:25.

CERTIFICATE OF SERVICE

I, Russell C. Molstad, Jr., Corporate Attorney for NorthWestern Public Service , hereby certify that on the 21st day of January, 2000, one original and ten true and correct copies, of Rebuttal Brief of NorthWestern Public Service in the above-referenced matter were mailed United States first-class mail to the following parties of record:

Mr. William Bullard
Executive Director
SD Public Utilities Commission
State Capitol Building
500 E Capitol Ave
Pierre SD 57501-5070



Russell C. Molstad, Jr.
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	FINDINGS OF FACT AND CONCLUSIONS OF LAW; NOTICE OF ENTRY OF ORDER NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application sought an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission further extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20-21, 1999, starting at 9:00 A.M. CDT, on October 20, 1999, in Room 413, State Capitol, Pierre, South Dakota. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a settlement agreement which increased the rates in the amount of $1,279,025. Staff requested that the Commission consider the settlement agreement on October 20, 1999. An issue related to NWPS' purchased gas adjustment (PGA) was separated from the rate case issues and was heard at the October 20, 1999, hearing. The issue was whether NWPS was entitled to recover certain costs it had placed in its PGA. On November 1, 1999, at a regularly scheduled meeting, the Commission approved the settlement agreement with an effective date of December 1, 1999. The PGA issue was briefed by NWPS and Commission Staff.

At its April 13, 2000, meeting, the Commission considered the remaining PGA issue. The Commission found that the portion of the $588,000 for capacity costs from Northern Natural which NWPS has placed in its PGA is not a recoverable cost under the fuel clause and ordered NWPS to remove that amount from its PGA. The Commission further found that the allowed pipeline cost of service shall be the following costs listed on Exhibit 3: the pre-tax return, property taxes, and administrative costs of the Aberdeen pipeline. The Commission further found that Staff's request for an NWPS refund with interest must be denied as not allowed under SDCL 49-34A-25. (Commissioner Schoenfelder dissented.)

Based on the evidence of record, the Commission makes the following findings of fact and conclusions of law:

FINDINGS OF FACT

1. NWPS is a local distribution company. Tr. at 23. It is a division of NorthWestern Corporation and is a utility whose rates are regulated by the Commission. Tr. at 13, 55.

2. NorthWestern Energy Corporation (NEC) is a subsidiary of NorthWestern Corporation. Tr. at 55. NEC is a non-regulated marketing arm of NWPS. Tr. at 8. As a non-regulated marketing entity, NEC is able to acquire natural gas supplies and capacity on interstate pipelines and then bundle those services to provide individual customers with gas service. Tr. at 13.

3. Nekota is a direct subsidiary of NEC. Tr. at 55. Nekota was created to hold the physical assets of a pipeline that bypassed the Northern Natural Gas (NNG) pipeline by connecting to the Northern Border pipeline (NBPL). Tr. at 21, 30-31. The bypass pipeline (hereafter referred to as the Aberdeen Pipeline) runs from Aberdeen to the NBPL. Tr. at 21, 66.

4. As a regulated utility, NWPS tracks the costs of acquiring capacity and procuring natural gas and these costs are billed to customers through the purchased gas adjustment (PGA). Tr. at 12. Each month the costs that are actually incurred are compared to the costs recovered though rates and any differential is trued up and reserved for a future recovery or refund back to the customer. Tr. at 12-13.

5. In February of 1996, NWPS was experiencing a shortage of firm capacity necessary to meet firm requirements. Tr. at 16-17. In order to alleviate this shortage, NWPS considered bypassing NNG by building a pipeline to Aberdeen from the NBPL. Tr. at 21. NNG operates a large capacity interstate pipeline which provided 49,000 MMBtus to NWPS. Tr. at 23. NWPS also wanted to negotiate other provisions with NNG, notably realigning its delivery point capacities and turning back field firm capacity for market firm capacity. Tr. at 27-29. Field firm capacity refers to production ar a capacity. Tr. at 28. Local distribution companies which contracted for firm market pipeline capacity from NNG were obligated to take field firm capacity. Tr. at 27-28. Field firm capacity was of no value to NWPS due to the location of the capacity. Tr. at 28-29.

6. On December 21, 1990, NWPS entered into a letter agreement with NNG which stated that NWPS agreed to maintain existing firm entitlement levels for a minimum of ten years and use NNG's system for all throughput for ten years for communities currently served by NNG (hereafter referred to as exclusivity provision). Tr. at 26; Exhibit 2.

7. NWPS stated that NNG agreed to waive this exclusivity provision if NEC bought enough services from NNG. Tr. at 31. NNG also agreed to allow NWPS to realign its delivery point capacities and turn back field firm for market firm. Tr. at 31-32; Exhibit 8.

8. The bypass pipeline was completed in late October of 1996. Tr. at 66. The pipeline cost $1,185,000.00. Tr. at 82.

9. Effective November 1, 1996, NWPS and NEC entered into an agreement allowing NWPS to purchase capacity from NEC on the Aberdeen pipeline. Tr. at 136; Late-filed Exhibit, Aberdeen City-Gate Transportation Services Agreement. NWPS pays all of the Aberdeen pipeline's inspection costs and operation and maintenance expenses for the first five years. Tr. at 137.

10. On February 14, 1997, NEC entered into a contract with NNG to buy 5000 MMBtus plus deferred delivery service. Tr at 96; Late-filed Exhibit, Letter Agreement between NEC and NNG. The capacity is used by NEC for its agency business. Tr. at 79. The contract was for five years. Tr. at 95.

11. On February 14, 1997, NWPS entered into a letter agreement with NNG. Exhibit 8. The agreement contained provisions which waived the exclusivity provision, changed delivery point capacity, and allowed the purchase of market firm to replace field firm. Tr. at 38-39; Exhibit 8.

12. In its November 1, 1996, PGA filing with an effective date of December 1, 1996, NWPS placed $576,000.00 into the PGA and identified the amount as "NBPL-Aberdeen capacity." Tr. at 134, 136, 139, 146; Exhibit 5. This amount actually contained costs associated with the Aberdeen pipeline owned by Nekota and costs paid by NEC to NNG for capacity. Exhibit 3. Commission Staff was unaware that NWPS was flowing costs of an affiliate pipeline through the PGA. Tr at 145. NWPS conceded that the identification of the Aberdeen pipeline as "NBPL-Aberdeen capacity" would give no indication that it was actually an affiliate transaction. Tr. at 68.

13. NWPS claimed the following project benefits from the building of the Aberdeen pipeline: (1) removal of NNG exclusivity provision; (2) increase in peak day pipeline capacity; (3) increased reliability; (4) the turnback of field firm capacity and conversion to market firm capacity; (5) increased capacity credits; and (6) ability to maintain interruptible customers on peak days. Exhibit 3; Tr. at 37-41.

14. NWPS claimed the following costs of $824,000.00 associated with the Aberdeen pipeline: (1) $588,000.00 -- capacity costs paid to NNG for firm transportation and deferred delivery service; (2) $165,000.00 -- pre-tax return on Aberdeen pipeline; (3) $23,000.00 -- property taxes on Aberdeen pipeline; (4) $48,000.00 -- administrative costs for regulatory review, balancing, nominations, and procurement on NBPL. Exhibit 3. NWPS then assigned 70% of the costs to NWPS and 30% to NEC. *Id.* This assignment was based on a total assigned firm capacity of 21,500 MMBtus with 15,000 assigned to NWPS and 6,500 to NEC. *Id.* NWPS then flowed 70% of the $824,000.00 through the PGA. Exhibit 5.

15. NWPS stated that in order to buy an additional 15,000 MMBtus from NNG it would have cost $1,197,000.00 annually. Tr. at 36-37.

16. NWPS stated that the letter agreement between NNG and NEC for the purchase of 5000 MMBtus plus deferred delivery represented, in part, a buy-out of the exclusivity provision contained in the 1990 letter agreement between NWPS and NNG. Tr. at 73-74. However, NWPS was unable to identify any portion of the $588,000.00 that could be attributed to the claimed buy-out. Tr. at 101.

17. Under the letter agreement between NEC and NNG, NEC buys 5,000 MMBtus of firm pipeline capacity at a base rate, plus surcharges, and buys deferred delivery service at NNG's maximum rate. Tr. at 96. The base rate was $3.00 for the summer months and $3.50 for the winter months. Tr. at 97-98. The amount of $588,000.00 was based on actual costs incurred during 1998. Tr. at 98. The total amount paid will vary from year to year. Tr. at 96-97.

18. The 5000 MMBtus is capacity needed by NEC and is not excess capacity. Tr. at 100. When NEC sells that capacity, it keeps the revenues associated with those sales. Tr. at 80. Thus, the revenues are not used to offset the amount allocated to NWPS even though NWPS is allocated 70% of the costs of that capacity. *Id.* NEC sells that capacity to its agency customers Tr. at 79.

19. NWPS stated that it intended to allocate 70% of the $588,000.00 to NWPS for ten years. Tr. at 102. When asked why NWPS would be charged 70% of the $588,000.00 for ten years when the agreement between NEC and NNG was for five years, the response was that NEC will need capacity beyond five years and, after the five year agreement expired, the cost would probably be higher. Tr. at 102.

20. Commission Staff stated that the charges passed through the PGA should "be reduced to a level that reflects Nekota's cost of providing the capacity." Tr. at 134; Exhibit A. Commission Staff further stated that this adjustment be made effective retroactive to December 1996 and that the amount

disallowed be flowed back to the ratepayers, with interest, over a three year period through the PGA. Tr. at 134, 139.

21. The Commission finds that NWPS has failed to prove that 70% of the $588,000 allocated to it is a recoverable PGA cost. The $588,000.00 is a cost incurred by NEC for capacity that it needs and uses. Tr. at 79-80. Although NWPS maintained the $588,000.00 represented, in part, a buy-out of the exclusivity provision contained in the 1990 NWPS/NNG agreement, NWPS failed to show that the rates NEC pays to NNG are higher than normal rates. There was no showing that the agreement included additional costs associated with a buy-out of the exclusivity provision. NEC needs that capacity for itself, sells it to its agency customers, and keeps the revenues from those sales. Tr. at 79-80. Moreover, NWPS stated that a new contract for NEC capacity would probably be higher in five years. Tr. at 102.

22. NWPS' argument that purchasing additional capacity from NNG would have cost more than $576,000.00 ignores the essential problem presented in this case: a company may not pass through its PGA costs incurred by an affiliate for capacity used by the affiliate.

23. In addition, the Commission finds it very disturbing that NWPS would continue to be allocated 70% of the $588,000.00 for ten years when the agreement between NEC and NNG was for five years. If the $588,000.00 had indeed represented, in part, a buy-out of the exclusivity provision, why would NWPS continue to pay for that buy-out for an additional five years beyond what NNG allegedly required for the buy-out? Moreover, at the time the five year agreement between NEC and NWPS was entered into, the 1990 agreement that contained the exclusivity provision was set to expire in less than four years. Exhibit 2. NWPS' rationale for the additional five years was that NEC would need capacity beyond the first five years and rates would probably be higher. Tr. at 102. Of course this begs the question as to why, higher costs or not, NWPS should be responsible for paying for any of NEC's capacity needs.

24. The Commission finds that it will allow NWPS to flow through the PGA the costs associated with the Aberdeen pipeline. NWPS stated that it was entitled to all of the capacity on the pipeline. Tr. at 43, 57, 93. In addition, NWPS is paying for all of the Aberdeen pipeline's inspection costs and operation and maintenance expenses for the first five years. Tr. at 137. The Commission finds that the costs of $165,000 for pre-tax return, $23,000.00 for property taxes, and $48,000.00 for administrative costs are reasonable and shall be allowed. The Commission further finds that since these costs represent the entire pipeline, NWPS may not flow through the PGA any additional amounts it may pay NEC for capacity above 15,000 MMBtus. Further, if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity.

25. The Commission denies Commission Staff's request that NWPS be required to refund with interest any previous amounts collected pursuant to the allocation of 70% of the $588,000.00. The Commission finds that a refund is not allowed under SDCL 49-34A-25.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, 49-34A-23, 49-34A-25, and 49-34A-26.

2. SDCL 49-34A-25 provides as follows:

> The commission shall permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in wholesale rates for energy delivered, the delivered costs of fuel used in generation of electricity, the delivered cost of gas, ad valorem taxes paid, or commission approved fuel incentives. The amended rate schedules shall be filed with the commission on or before the effective date of the change in costs, and if the commission determines that the revised rate schedule is in error, the commission may within ten days of receipt thereof require by order the public utility to file a bond or other security upon such terms and conditions as the commission may require and for such purposes as contained in §§ 49-34A-17 and 49-34A-22. Such rates may go into effect on the date of the change in costs subject to the above refund provisions. Failure of the commission to enter an order in regard thereto shall be deemed approval. The public utility may appeal such order pursuant to and in accordance with § 49-34A-62.

3. The Commission finds that the allocation of 70% of $588,000.00 to NWPS' fuel clause is unreasonable and not allowed under SDCL 49-34A-25. NWPS has failed to prove that 70% of the $588,000 allocated to it is a recoverable PGA cost. *See* Finding of Fact 21.

4. The Commission finds that it will allow NWPS to flow through the PGA the costs associated with the Aberdeen pipeline. NWPS stated that it was entitled to all of the capacity on the pipeline. Tr. at 43, 57, 93. The Commission finds that the costs of $165,000 for pre-tax return, $23,000.00 for property taxes, and $48,000.00 for administrative costs are reasonable and shall be allowed. The Commission further finds that since these costs represent the entire pipeline, NWPS may not flow through the PGA any additional amounts it may pay NEC for capacity above 15,000 MMBtus. Further, if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity.

5. The Commission finds it is unable to order NWPS to refund with interest any previous amounts collected pursuant to the allocation of 70% of the $588,000.00. The Commission finds that a refund is not allowed under SDCL 49-34A-25 based on the language that states that "[f]ailure of the commission to enter an order in regard thereto shall be deemed approval."

It is therefore

ORDERED, that NWPS shall remove from its PGA the portion of the $588,000 for capacity costs from NNG which NWPS has placed in its PGA.

NOTICE OF ENTRY OF ORDER

PLEASE TAKE NOTICE that this Order was duly entered on the 27th day of April, 2000. Pursuant to SDCL 1-26-32, this Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties.

Dated at Pierre, South Dakota, this 27th day of April, 2000.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 4/27/00

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

JAMES A. BURG, Chairman

PAM NELSON, Commissioner

LASKA SCHOENFELDER, Commissioner, dissenting

Dissent of Commissioner Schoenfelder

Even though we deal with complex issues and dockets on a daily basis, this docket was more difficult than most. NorthWestern Public Service (NWPS), which is regulated, joined with unregulated affiliates Northwestern Energy Corporation (NEC) and Nekota Resources, Incorporated (Nekota) to increase pipeline capacity. The increased capacity came from Northern Natural Gas (NNG), and from Northern Border Pipeline Company via the Nekota Pipeline. NEC negotiated with NNG on NWPS contractual matters, while Nekota, a subsidiary of NEC, built a pipeline which provided capacity for NWPS. All of this took place over three years ago. This already complex matter was further complicated when the record was limited to testimony brought to the table on the day of hearing and several late-filed exhibits.

The majority made their decision in spite of an undeveloped record that left too many questions unanswered. The majority decision may even be one with which I could agree if there were enough facts to support it. Conversely, NWPS took steps in 1996 to alleviate a system capacity shortage and eliminate an onerous NNG contractual clause. NWPS believes this was done in a creative and cost-effective manner. The majority's decision could effectively penalize NWPS for lowering customer gas costs. Again, the record does not offer enough support for this conclusion.

I am deeply disturbed that it is now necessary to address this issue. The Nekota Pipeline was built over three years ago. The NNG contract was changed over three years ago. The costs have since been included in the purchased gas adjustment (PGA) clause, unnoticed by staff. Staff should have certainly noticed this major new PGA cost item long before the rate case was filed.

NWPS may not be obligated to inform staff when this type of change occurs, but maybe they should. NWPS made it clear at the hearing that the project was an extremely significant capacity addition. Does NWPS believe major transactions should not receive scrutiny at the outset? If it was such a good deal NWPS should be willing to support it before ratepayers are asked to pay. NWPS and staff need to address their individual actions, and maybe the first step for both is by improvement in communication.



South Dakota Public Utilities Commission

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Jim Burg
Chairman
Pam Nelson
Vice-Chairman
Laska Schoenfelder
Commissioner

William Bullard Jr.
Executive Director

Harlan Best
Martin C. Bettmann
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Karen E. Cremer
Terry Emerson
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Dave Jacobson
Jennifer Kirk
Bob Knadle
Delaine Kolbo
Charlene Lund
Gregory A. Rislov
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Rolayne Ailts Wiest

June 8, 2000

Mr. Alan D. Dietrich
Vice President - Legal Administration
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Sioux Falls, SD 57104-6403

Mr. Thomas P. Hitchcock
Executive Vice President
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Huron, SD 57350

Ms. Susan Anderson Bachman
Attorney at Law
NorthWestern Corporation
125 S. Dakota Avenue, Suite 1100
Sioux Falls, SD 57104-6403

Re: In the Matter of the Application of NorthWestern Public Service for Authority to Increase Rates for Natural Gas Service
Docket NG99-002

Dear Folks:

Enclosed each of you will find a copy of Motion to Compel NorthWestern Public Service to Comply with Commission Order in the above captioned matter. This is intended as service upon you by mail.

Very truly yours,

Karen E. Cremer
Staff Attorney

KEC:dk
Enc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	MOTION TO COMPEL NORTHWESTERN PUBLIC SERVICE TO COMPLY WITH COMMISSION ORDER NG99-002

On April 27, 2000, the South Dakota Public Utilities Commission entered its Findings of Fact and Conclusions of Law; Notice of Entry of Order in Docket NG99-002 which dealt with NorthWestern Public Service's (NWPS) recovery of costs incurred as a result of purchasing capacity on a pipeline owned by Nekota, a direct subsidiary of NorthWestern Energy Corporation which is a non-regulated marketing arm of NorthWestern Public Service. On May 4, 2000, NWPS filed their first PGA subsequent to the Commission's decision.

Since the filing of the May 4, 2000, PGA, Commission Staff and representatives of NWPS have held discussions on whether the filed PGA complies with the Commission's order. It is Commission Staff's position that NWPS' PGA filing does not comply with the Commission's April 27, 2000, order in two instances. First, in its May 4, 2000, PGA compliance filing, NWPS included "$42,918 in actual 1999 property taxes associated with the Nekota pipeline. . ." in direct violation of Conclusion of Law 4. Attachment A (filed CONFIDENTIAL). Second, NWPS used the proportion of actual volumetric capacity released to total physical capacity of the pipeline as compared to capacity released to capacity utilized by NWPS. Again Commission Staff's position is that this violates Conclusion of Law 4.

NWPS is ignoring the Commission's directive found in Findings of Fact 14 and 24 which state as follows:

> 14. NWPS claimed the following costs of $824,000.00 associated with the Aberdeen pipeline: (1) $588,000.00 -- capacity costs paid to NNG for firm transportation and deferred delivery service; (2) $165,000.00 -- pre-tax return on Aberdeen pipeline; (3) $23,000.00 -- property taxes on Aberdeen pipeline; (4) $48,000.00 -- administrative costs for regulatory review, balancing, nominations, and procurement on NBPL. Exhibit 3. NWPS then assigned 70% of the costs to NWPS and 30% to NEC. *Id.* This assignment was based on a total assigned firm capacity of 21,500 MMBtus with 15,000 assigned to NWPS and 6,500 to NEC. *Id.* NWPS then flowed 70% of the $824,000.00 through the PGA. Exhibit 5.
>
> 24. The Commission finds that it will allow NWPS to flow through the PGA the costs associated with the Aberdeen pipeline. NWPS stated that it was entitled to all of the capacity on the pipeline. Tr. at 43, 57, 93. In addition,

NWPS is paying for all of the Aberdeen pipeline's inspection costs and operation and maintenance expenses for the first five years. Tr. at 137. The Commission finds that the costs of $165,000 for pre-tax return, $23,000.00 for property taxes, and $48,000.00 for administrative costs are reasonable and shall be allowed. The Commission further finds that since these costs represent the entire pipeline, NWPS may not flow through the PGA any additional amounts it may pay NEC for capacity above 15,000 MMBtus. Further, if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity.

NWPS is further ignoring the directive in Conclusion of Law 4 which states as follows:

> 4. The Commission finds that it will allow NWPS to flow through the PGA the costs associated with the Aberdeen pipeline. NWPS stated that it was entitled to all of the capacity on the pipeline. Tr. at 43, 57, 93. The Commission finds that the costs of $165,000 for pre-tax return, $23,000 for property taxes and $48,000 for administrative costs are reasonable and should be allowed. The Commission further finds that since these costs represent the entire pipeline, NWPS may not flow through the PGA any additional amounts it may pay NEC for capacity above 15,000 MMBtus. Further, if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity.

In other words, the Commission ordered NWPS to pass $23,000 of property tax through the PGA but instead, NWPS has passed $42,918 through the PGA. Further, NWPS used the proportion of capacity released based on total physical capacity instead of actual capacity utilized. Both actions are contrary to the decision of the Commission.

WHEREFORE, Commission Staff requests that the Commission enter an order declaring:

1. that NWPS is not complying with the Findings of Fact and Conclusions of Law dated April 27, 2000;

2. that such noncompliance is an intentional violation of SDCL 49-34A-9, 49-34A-12 and 49-34A-21;

3. that NWPS must comply with the Commission's order dated April 27, 2000; and

4. for such other and further relief as the Commission may deem appropriate under the circumstances.

Dated this 8th day of June, 2000.

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501
Telephone 605-773-3201

CERTIFICATE OF SERVICE

I hereby certify that copies of Motion to Compel NorthWestern Public Service to Comply with Commission Order were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the addresses shown below on this the 8th day of June, 2000.

Mr. Alan D. Dietrich
Vice President - Legal Administration
NorthWestern Corporation
125 S. Dakota Avenue, Suite 1100
Sioux Falls, SD 57104-6403

Mr. Thomas P. Hitchcock
Executive Vice President
NorthWestern Energy Corporation
33 Third Street S.E.
Huron, SD 57350

Ms. Susan Anderson Bachman
Attorney at Law
NorthWestern Corporation
125 S. Dakota Avenue, Suite 1100
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Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

NG99-002

CONFIDENTIAL

#6

NorthWestern™
CORPORATION

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June 22, 2000

RECEIVED
JUN 26 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol
Pierre, SD 57501

Re: In the Matter of the Application of NorthWestern
Public Service for Authority to Increase Rates
For Natural Gas Service
Docket No. NG99-002

Dear Mr. Bullard:

Enclosed are the original and ten copies of the Response to Motion to Compel and Request for Clarification in the above referenced matter. This is intended as service upon you by mail.

Sincerely,

Susan Anderson Bachman

Susan Anderson Bachman
Vice President – Legal Services

Enclosures

RECEIVED
JUN 2 6 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER	)	**DOCKET NO. NG99-002**
OF THE APPLICATION OF	)	
NORTHWESTERN PUBLIC SERVICE	)	**RESPONSE TO MOTION**
FOR AUTHORITY TO INCREASE	)	**TO COMPEL**
RATES FOR NATURAL GAS SERVICE	)	**AND**
	)	**REQUEST FOR**
	)	**CLARIFICATION**

On June 9, 2000, Northwestern Public Service, a division of Northwestern Corporation (NPS), received a Motion to Compel by the South Dakota Public Utilities Commission (Commission) to comply with Commission Order NG99-002 dated April 27, 2000. NPS, for its Response to the Motion to Compel, states and alleges the following:

PROPERTY TAX FLOW THROUGH THE PGA

1. In its May 2, 2000 Purchase Gas Adjustment (PGA) filing, NPS included $42,918 for the actual 1999 property taxes associated with the Aberdeen pipeline.

2. NPS filed its PGA for May 2000 to include the 1999 actual property tax assessment pursuant to SDCL 49-34A-25 and to be consistent with NPS's Natural Gas Adjustment Clause Rates Tariff, Revised Sheet No 9b and 9.1 which allows "[a]ll ad valorem taxes accrued and adjusted for actual tax payments".

3. NPS specifically noted this adjustment for 1999 actual taxes assessed versus the $23,000 (which was based on 1998 actual property tax assessments) in its explanation letter submitted to the Commission with its May 2, 2000 PGA filing.

4. Subsequent to NPS's May 2000 PGA filing, NPS and Commission Staff had extensive conversations. Commission Staff's position is that since the Commission Order in Docket NG99-002 listed $23,000 for property taxes the adjustment for property taxes for flow through the PGA should be $23,000.

5. In the spirit of cooperation with the Commission, NPS included the $23,000 in actual 1998 assessed property taxes in its June 2000 PGA filing. Thus, in its June 2000 PGA filing and in all future PGA filings, NPS will include the $23,000 amount for property tax treatment pursuant to the Commission Order in Docket NG99-002.

6. Therefore, NPS denies that it has failed to comply with the Commission Order in Docket NG99-002, Conclusion of Law No. 4, with respect to the flow through of property taxes associated with the Aberdeen pipeline.

7. NPS respectfully requests the Commission to clarify whether NPS should include the amount of $23,000 in its future PGA filings or include the actual amount of property taxes assessed as per SDCL 49-34A-25 and consistent with NPS's Natural Gas Adjustment Clause Rates Tariff.

DETERMINATION OF APPROPRIATE CREDIT FOR CAPACITY USED ON THE ABERDEEN PIPELINE BY OTHER ENTITIES

8. Commission Staff also alleges that NPS violated the Commission Order in Docket NG99-002 because NPS used the actual volumetric capacity released to total physical capacity of the Aberdeen pipeline as compared to capacity released to capacity utilized by NPS.

9. NPS states that the Commission Order in Docket NG99-002 is clear regarding the determination of the appropriate credit to NPS cost responsibility of the Aberdeen pipeline when any other entity other than NPS uses capacity on the Aberdeen pipeline. Therefore, NPS submits that it is not in violation of Commission Order NG99-002 with respect to this issue.

10. In Conclusion of Law No. 4 of the Commission Order in NG99-002, the Commission acknowledges that NPS is entitled to all the capacity on the Aberdeen pipeline and that NPS is responsible for all of the costs associated with the Aberdeen pipeline. Thus, NPS is the only party with firm entitlement rights on the Aberdeen pipeline. All other shippers that may use the Aberdeen pipeline have interruptible status.

11. The Commission Order and record in Docket NG99-002 reflect the annual costs associated with the Aberdeen pipeline allowed by the Commission are $236,000 with a pipeline capacity of 24,000 Dekatherms per day (Transcript of Contested Case, October 20, 1999, page 40).

12. The industry standard and accepted practice and accepted FERC preference for calculating interruptible pipeline rates is based on 100% load factor derivation of the firm rate. For example, if an interruptible shipper on a pipeline uses an average of 10% of a pipeline's daily capacity, that

shipper would be responsible for a proportionate 10% share of the pipeline's annual costs.

13. NPS applied this industry standard methodology for the development of the appropriate credit to be applied against total allowed PGA costs associated with the Aberdeen pipeline.

14. With regard to the Aberdeen pipeline, the interruptible rate is calculated as follows: $236,000 annual cost divided by 24,000 Dekatherms per day capacity divided by 365 days per year equals $0.026941 per Dekatherm.

15. Commission Staff's interpretation of Commission Order NG99-002 completely disregards industry standards and accepted practice for cost allocation and rate design. Commission Staff's interpretation ignores the basic premise that pipelines are designed, sized and built to meet peak day capacity needs. If pipeline rates were designed solely on actual capacity utilized, rates would be lower in the winter season (due to higher heating use) and higher during the off-peak months (due to lower heating use).

16. If Commission Staff's interpretation of Commission Order NG99-002 pertaining to this issue stands, other entities may be driven away from using the Aberdeen pipeline during off-peak periods because of other cost-effective alternatives from other pipelines that serve Aberdeen. For example, the maximum off-peak interruptible rate for Northern Natural Gas Company's pipeline is currently a lower cost alternative to that of Commission Staff's interpretation of rate structure. This would eliminate any credits to be applied against total allowed PGA costs associated with the Aberdeen pipeline that ultimately pass through to NPS customers.

17. The methodology utilized by NPS for the development of the appropriate credit to be applied against total allowed PGA costs associated with the Aberdeen pipeline is not contrary to the Commission's decision in Conclusion of Law No. 4 in the Commission Order in NG99-002. Therefore, NPS denies that it has failed to comply with such Order regarding this issue.

18. NPS respectfully requests the Commission to clarify the determination of the appropriate calculation of credit for capacity used on the Aberdeen pipeline by other entities according to industry standards and accepted industry practices for NPS and Commission Staff.

WHEREFORE, NPS requests that the Commission enter an Order declaring:

1. that NPS is complying with the Findings of Fact and Conclusions of Law of the Commission's Order dated April 27, 2000;

2. that NPS is not intentionally violating SDCL 49-34A-9, 49-34A-12 and 49-34A-21;

3. that the Commission clarify whether NPS should include the amount of $23,000 in its future PGA filings or include the actual amount of property taxes assessed as per SDCL 49-34A-25 and consistent with NPS's Natural Gas Adjustment Clause Rates Tariff;

4. that the Commission clarify the determination of the appropriate calculation of credit for capacity used on the Aberdeen pipeline by other entities according to industry standards and accepted industry practice; and

5. for such other and further relief as the Commission may deem appropriate under the circumstances.

Dated this 22nd day of June, 2000.

Susan Anderson Bachman

Susan Anderson Bachman
Vice President – Legal Services
NorthWestern Public Service
125 South Dakota Avenue
Sioux Falls, SD 57104
(605) 978-2911

CERTIFICATE OF SERVICE

I hereby certify that copies of the Response to Motion to Comply with Commission Order and Request for Clarification were served on the following by mailing the same to the South Dakota Public Utilities Commission by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this 22nd day of June, 2000.

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

Susan Anderson Bachman

Susan Anderson Bachman
Vice President – Legal Services
NorthWestern Public Service
125 South Dakota Avenue
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November 20, 2000

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

RE: In the Matter of the Application of NorthWestern
Public Service for Authority to Increase Rates
For Natural Gas Service
Docket No. NG99-002

Dear Mr. Bullard:,

Enclosed are the original and ten copies of the Memorandum of NorthWestern Public Service Concerning Status of Nekota Resources, Inc. Pipeline in the above referenced matter. This is intended as service upon you by mail.

Sincerely,

Susan Anderson Bachman

Susan Anderson Bachman
Vice President – Legal Services

Enclosures

RECEIVED
DEC 06 2000
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))	DOCKET NO. NG99-002

MEMORANDUM OF NORTHWESTERN PUBLIC SERVICE CONCERNING STATUS OF NEKOTA RESOURCES, INC. PIPELINE

Introduction

In order to understand the relationship of the various NorthWestern Corporation (the "Corporation") entities, some background information with regard to their formation and purposes is helpful. Where specific statements in this Memorandum are related to evidence presented at the hearing in this matter on October 20, 1999, references to the transcript of that hearing will be by page number as (TR __).

The Corporation changed its name from NorthWestern Public Service Company in 1998, retaining the name NorthWestern Public Service for its electric and natural gas utility operations in South Dakota and Nebraska. (TR 54-55). In this Memorandum, to avoid confusion, we will refer to both the Corporation prior to the name change and the utility division from 1998 forward as "NorthWestern."

NorthWestern formed NorthWestern Energy Corporation ("NEC") on August 27, 1996, as a wholly-owned subsidiary South Dakota corporation. (TR 55). NEC was formed principally to "engage in activities related to the sales . . . of energy and energy-related products and services." It was to serve as an unregulated energy provider, to allow NorthWestern to compete with other non-regulated marketers of energy. (TR 8, 10-11, 13). Where NEC was able to make arrangements with such end-use customers, it would arrange for upstream transportation of the energy sold through NorthWestern's distribution facilities, paying the same transportation and distribution through NorthWestern's or other applicable distributors' facilities, paying the same delivery charges that are paid by other third party marketers. Additionally, NorthWestern transferred its regulatory group to NEC, with such resources serving a dual role: supervising the energy sales and transportation scheduling of NEC and continuing to provide the regulatory and natural gas purchasing services to the Corporation pursuant to a management services agreement. (TR 8-10). NEC has helped increase throughput on NorthWestern's distribution systems, retain traditional customers on those systems, and acquire new NEC customers on other distribution systems. (TR 10).

On October 31, 1996, NorthWestern formed Nekota Resources, Inc. ("Nekota") as a South Dakota corporation and as a wholly-owned subsidiary of NEC. (TR 55). The purposes of formation of Nekota announced in its Articles of Incorporation filed with the South Dakota Secretary of State included the "operation of facilities for the supply and delivery of energy." (TR 30-31). Thus, while NEC was created to sell energy to end-use customers, Nekota was formed to be the owner of energy supply and delivery facilities. Its role was "to get competitively-priced pipeline capacity to meet the needs" of NorthWestern's residential and business customers. (TR14).

As explained by Thomas Hitchcock at the hearing, NorthWestern built the Nekota pipeline because it was unable to obtain, through negotiations with Northern Natural Gas Company ("Northern"), capacity for the Aberdeen area on a basis comparable to that which it could receive through construction of the pipeline. (TR 14-43). The Nekota pipeline also added other tangible benefits for NorthWestern and its customers. Among these is improved delivery capability on peak days (TR 19-21). Additionally, through negotiations with Northern, NEC, on behalf of NorthWestern, was also able to exchange Northern field capacity (of little or no value) for additional firm market area capacity from Northern (TR 27-30, 37-40) and to reassign delivery point capacity at various of NorthWestern's interconnection points with Northern (TR 37-38). Finally, the additional capacity that Nekota provided to NorthWestern assisted the retention of interruptible customer loads (TR 39-40)

Regulatory Treatment of Nekota Pipeline

As noted above, Nekota was created, and the pipeline was built to be a dedicated delivery facility for NorthWestern, and when capacity was available, through NorthWestern for NEC. As explained at the hearing, NorthWestern has contracted for 15,000 MMBtu per day of capacity on the Nekota pipeline but has the ability to utilize 100% of the pipeline capacity "on any day they need it." (TR 36, 43-44, 138). As explained below, the structure of the Corporation, NorthWestern, NEC, and Nekota entities makes it possible for the pipeline to remain a dedicated facility.

NorthWestern is a "public utility" as defined in SDCL 49-34A-1(12) because it is a "person operating, maintaining, or controlling in this state equipment or facilities for the purpose of providing gas or electric service to or for the public in whole or in part, in this state." Its rates and charges are subject to regulation by the South Dakota Public Utilities Commission (the "Commission"), pursuant to SDCL 49-34A-6.

NEC does not operate, maintain or control equipment or facilities for gas or electric service, it merely contracts with end-use customers for the sale of energy and arranges for the delivery of such energy through the facilities of public utilities. Thus, NEC is not a public utility regulated by the Commission in South Dakota, but any arrangements between NEC and NorthWestern may be scrutinized by the Commission, pursuant to SDCL 49-34A-19.2, with any unreasonable profits by NEC disallowable.

Under SDCL 49-34A-1(8) gas service is defined as the "retail sale of natural gas . . . distributed through a pipeline to fifty or more customers or the sale of transportation services by an intrastate natural gas pipeline." Nekota owns and operates a pipeline facility, but that pipeline facility is **not** an "intrastate natural gas pipeline." SDCL 49-34A-1(9A) defines an "intrastate natural gas pipeline" as follows:

> "Intrastate natural gas pipeline," any natural gas pipeline located entirely within the state that transports gas from a receipt point to one or more locations for customers other than the pipeline operator. However, the terms does not apply if there is only one customer and the customer is a wholly-owned subsidiary of the pipeline operator, the customer is the parent company of the pipeline operator, or the customer and the pipeline operator are wholly-owned subsidiaries of the same parent company. Further, the terms does not apply to natural gas lines and appurtenant facilities used to gather gas from natural gas production facilities or sites and move the gas to an interconnecting transportation pipeline system.

Nekota is a wholly-owned subsidiary of the Corporation, through the Corporation's ownership of NEC. As a division of the Corporation, NorthWestern is synonymous with the Corporation for purposes of ownership of Nekota and NEC. Nekota only transports gas for its parent, NEC, and does not hold itself out as a common carrier or open access pipeline. If it were to do so, it would jeopardize the purpose for which it was formed, i.e. to secure the right to access for 100% of its capacity for NorthWestern. To the extent NorthWestern does not need the capacity, it releases such capacity to NEC, at rates that are subject to Commission approval (as affiliate transactions between NEC and NorthWestern). In addition, as an affiliate of NorthWestern, the rates for transportation on Nekota paid by NEC (and passed on to NorthWestern through a contract) are subject to Commission regulation, pursuant to SDCL 49-34A-19.2, in determining that profits made by an affiliate in the sale of services to a "public utility" are not unreasonable. Application of Montana-Dakota Utilities Co., 278 N.W.2d 189 (S.D. 1979).

Conclusion

This memorandum is limited to the issue of the regulatory treatment of the Nekota pipeline. The other issues raised in this proceeding, in the Motion to Compel, concerning property tax and the transportation charges to be paid by NEC, were addressed in documents previously filed in this matter.

The Nekota pipeline is not an intrastate natural gas pipeline, subject to independent regulation by the Commission and is not required to file rate case applications, pursuant to SDCL 49-34A in order to attempt to change its charges for pipeline capacity to its sole customer, NEC. However, any change in such charges, to the extent that NorthWestern wishes to pass them on to its customers, would have to be supported by evidence as to reasonableness by NorthWestern, pursuant to SDCL 49-34A-19.2. Thus, even though Nekota is not independently a regulated entity, its transactions with NEC (to the extent that

transportation services on the existing and another future pipeline are used by NorthWestern) are subject to Commission review.

Respectfully submitted, this 20th day of November, 2000.

NORTHWESTERN PUBLIC SERVICE,
division of NorthWestern Corporation

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CERTIFICATE OF SERVICE

I hereby certify that copies of the Memorandum of NorthWestern Public Service Concerning Status of Nekota Resources, Inc. Pipeline were served on the following by mailing the same to the South Dakota Public Utilities Commission by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this 20th day of November, 2000.

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

Susan Anderson Bachman

Susan Anderson Bachman
Attorney
NorthWestern Public Service
125 South Dakota Avenue
Sioux Falls, SD 57104
(605) 978-2911

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	)))))	ORDER GRANTING IN PART AND DENYING IN PART MOTION TO COMPEL NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application sought an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission further extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20-21, 1999, starting at 9:00 A.M. CDT, on October 20, 1999, in Room 413, State Capitol, Pierre, South Dakota. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a settlement agreement which increased the rates in the amount of $1,279,025. Staff requested that the Commission consider the settlement agreement on October 20, 1999. An issue related to NWPS' purchased gas adjustment (PGA) was separated from the rate case issues and was heard at the October 20, 1999, hearing. The issue was whether NWPS was entitled to recover certain costs it had placed in its PGA. On November 1, 1999, at a regularly scheduled meeting, the Commission approved the settlement agreement with an effective date of December 1, 1999. The PGA issue was briefed by NWPS and Commission Staff.

At its April 13, 2000, meeting, the Commission considered the remaining PGA issue. The Commission found that the portion of the $588,000 for capacity costs from Northern Natural which NWPS has placed in its PGA is not a recoverable cost under the fuel clause and ordered NWPS to remove that amount from its PGA. The Commission further found that the allowed pipeline cost of service shall be the following costs listed on Exhibit 3: the pre-tax return, property taxes, and administrative costs of the Aberdeen pipeline. The Commission further found that Staff's request for an NWPS refund with interest must be denied as not allowed under SDCL 49-34A-25. (Commissioner Schoenfelder dissented.)

On June 8, 2000, Commission Staff filed a Motion to Compel NorthWestern Public Service to Comply with Commission Order. In its motion, Commission Staff stated that NWPS' May 4, 2000 PGA filing included $42,918.00, representing actual 1999 property taxes for the Aberdeen pipeline. Commission Staff cited to the Commission's findings of fact 14 and 24 which allowed $23,000.00 for property taxes. *See* Findings of Fact and Conclusions of Law; Notice of Entry of Order, issued April 27, 2000 (hereafter Commission's Order). Commission Staff also stated that "NWPS used the proportion of actual volumetric capacity released to total physical capacity of the pipeline as compared to capacity released to capacity utilized by NWPS." Commission Staff stated that this was

contrary to the Commission's Order which stated that "if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity." Commission's Order, Finding of Fact 24. Commission Staff requested that the Commission find that NWPS is not complying with the Commission's Order, that such noncompliance is an intentional violation, and order NWPS to comply with the Commission's Order.

On June 26, 2000, the Commission received from NWPS a Response to Motion to Compel and Request for Clarification. In its response to the property tax issue, NWPS stated that it included $42,918.00 in property taxes in the May PGA because that was the pipeline's actual 1999 property taxes. NWPS stated that after discussing the matter with Staff, NWPS included $23,000.00, which was the pipeline's actual 1998 property taxes, in its June 2000 PGA filing. NWPS asked that "the Commission clarify whether NPS should include the amount of $23,000.00 in its future PGA filings or include the actual amount of property taxes assessed as per SDCL 49-34A-25 and consistent with NPS's Natural Gas Adjustment Clause Rates Tariff." On the capacity issue, NWPS stated that since it is the only party with firm entitlement rights on the pipeline, all other shippers have interruptible status. NWPS further stated that the industry standard for calculating interruptible pipeline rates is to base the rates on a 100% load factor derivation of the firm rate.

At its August 22, 2000, meeting, the Commission considered the Motion to Compel. The Commission requested that the parties address the question of whether the pipeline is subject to regulation as an intrastate natural gas pipeline. On December 6, 2000, the Commission received a response to this question from NWPS, entitled Memorandum of NorthWestern Public Service Concerning Status of Nekota Resources, Inc. Pipeline.

At its January 17, 2001, meeting, the Commission considered the Motion to Compel. The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-18, 1-26-19, 49-34A-2, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-16, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-20, 49-34A-21, 49-34A-22, 49-34A-23, 49-34A-25, and 49-34A-26. After listening to comments by NWPS and Commission Staff, the Commission granted the Motion to Compel in part and denied it in part. With respect to Staff's issue concerning the assignment of costs, the Commission denied the Motion to Compel. The Commission defined the word "proportionate" as used in the Commission's Order as "properly related to the characteristics of the service being rendered" or, in other words, a recognition of the fact that a firm capacity right is different than an interruptible right. Thus, NWPS' jurisdictional cost of service for the Aberdeen pipeline should be credited for off-system sales based upon the off-system sales being credited at a 100% load factor rate. With respect to Staff's issue concerning property taxes, the Commission grants the Motion to Compel. The Commission restates that it allowed $23,000.00 in property taxes, which was the number presented by NWPS to the Commission at the hearing. NWPS is required to comply with the Commission's Order regarding this finding. On the question of whether the pipeline is an intrastate natural gas pipeline as defined by 49-34A-1(9A), the Commission decided to take that question under advisement. It is therefore

ORDERED, that NWPS' jurisdictional cost of service for the Aberdeen pipeline should be credited for off-system sales based upon the off-system sales being credited at a 100% load factor rate; and it is

FURTHER ORDERED, that NWPS is required to comply with the Commission's Order and continue to use $23,000.00 as the amount allowed for property taxes.

Dated at Pierre, South Dakota, this 29th day of January, 2001.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 1/29/01

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

JAMES A. BURG, Chairman

PAM NELSON, Commissioner

LASKA SCHOENFELDER, Commissioner

NG09-002

CONFIDENTIAL

#7

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHWESTERN PUBLIC SERVICE FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE	))))))	ORDER FINDING PIPELINE IS NOT AN INTRASTATE NATURAL GAS PIPELINE AS DEFINED BY SDCL 49-34A-1(9A) NG99-002

On June 1, 1999, NorthWestern Public Service, a division of NorthWestern Corporation (NWPS), filed with the Public Utilities Commission (Commission) an application to increase natural gas rates in South Dakota. The application sought an overall increase in rates in the amount of $2,108,112 or approximately 6%. The Company requested a change in rates to become effective for billings after July 1, 1999.

At its regularly scheduled meeting of June 22, 1999, the Commission found that pursuant to SDCL 49-1A-8, NWPS shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further established an intervention deadline of July 22, 1999. Pursuant to SDCL 49-34A-14, the Commission suspended the operation of the schedule of rates proposed by NWPS for 90 days beyond July 1, 1999. By Order dated September 14, 1999, the Commission further extended the suspension through December 1, 1999.

The Commission scheduled the matter for hearing on October 20-21, 1999, starting at 9:00 A.M. CDT, on October 20, 1999, in Room 413, State Capitol, Pierre, South Dakota. On October 18, 1999, Commission Staff notified the Commission that NWPS and Commission Staff had reached a settlement agreement which increased the rates in the amount of $1,279,025. Staff requested that the Commission consider the settlement agreement on October 20, 1999. An issue related to NWPS' purchased gas adjustment (PGA) was separated from the rate case issues and was heard at the October 20, 1999, hearing. The issue was whether NWPS was entitled to recover certain costs it had placed in its PGA. On November 1, 1999, at a regularly scheduled meeting, the Commission approved the settlement agreement with an effective date of December 1, 1999. The PGA issue was briefed by NWPS and Commission Staff.

At its April 13, 2000, meeting, the Commission considered the remaining PGA issue. The Commission found that the portion of the $588,000 for capacity costs from Northern Natural which NWPS has placed in its PGA is not a recoverable cost under the fuel clause and ordered NWPS to remove that amount from its PGA. The Commission further found that the allowed pipeline cost of service shall be the following costs listed on Exhibit 3: the pre-tax return, property taxes, and administrative costs of the Aberdeen pipeline. The Commission further found that Staff's request for an NWPS refund with interest must be denied as not allowed under SDCL 49-34A-25. (Commissioner Schoenfelder dissented.)

On June 8, 2000, Commission Staff filed a Motion to Compel NorthWestern Public Service to Comply with Commission Order. In its motion, Commission Staff stated that NWPS' May 4, 2000 PGA filing included $42,918.00, representing actual 1999 property taxes for the Aberdeen pipeline. Commission Staff cited to the Commission's findings of fact 14 and 24 which allowed $23,000.00 for property taxes. *See* Findings of Fact and Conclusions of Law; Notice of Entry of Order, issued April 27, 2000 (hereafter Commission's Order). Commission Staff also stated that "NWPS used the proportion of actual volumetric capacity released to total physical capacity of the pipeline as

compared to capacity released to capacity utilized by NWPS." Commission Staff stated that this was contrary to the Commission's Order which stated that "if any entity other than NWPS uses capacity on the Aberdeen pipeline, then NWPS' responsibility for the costs of the pipeline shall be reduced in proportionate amount to the capacity used by the other entity." Commission's Order, Finding of Fact 24. Commission Staff requested that the Commission find that NWPS is not complying with the Commission's Order, that such noncompliance is an intentional violation, and order NWPS to comply with the Commission's Order.

On June 26, 2000, the Commission received from NWPS a Response to Motion to Compel and Request for Clarification. In its response to the property tax issue, NWPS stated that it included $42,918.00 in property taxes in the May PGA because that was the pipeline's actual 1999 property taxes. NWPS stated that after discussing the matter with Staff, NWPS included $23,000.00, which was the pipeline's actual 1998 property taxes, in its June 2000 PGA filing. NWPS asked that "the Commission clarify whether NPS should include the amount of $23,000.00 in its future PGA filings or include the actual amount of property taxes assessed as per SDCL 49-34A-25 and consistent with NPS's Natural Gas Adjustment Clause Rates Tariff." On the capacity issue, NWPS stated that since it is the only party with firm entitlement rights on the pipeline, all other shippers have interruptible status. NWPS further stated that the industry standard for calculating interruptible pipeline rates is to base the rates on a 100% load factor derivation of the firm rate.

At its August 22, 2000, meeting, the Commission considered the Motion to Compel. The Commission requested that the parties address the question of whether the pipeline is subject to regulation as an intrastate natural gas pipeline. On December 6, 2000, the Commission received a response to this question from NWPS, entitled Memorandum of NorthWestern Public Servi e Concerning Status of Nekota Resources, Inc. Pipeline.

At its January 17, 2001, meeting, the Commission considered the Motion to Compel. After listening to comments by NWPS and Commission Staff, the Commission granted the Motion to Compel in part and denied it in part. With respect to Staff's issue concerning the assignment of costs, the Commission denied the Motion to Compel. The Commission defined the word "proportionate" as used in the Commission's Order as "properly related to the characteristics of the service being rendered" or, in other words, a recognition of the fact that a firm capacity right is different than an interruptible right. Thus, NWPS' jurisdictional cost of service for the Aberdeen pipeline should be credited for off-system sales based upon the off-system sales being credited at a 100% load factor rate. With respect to Staff's issue concerning property taxes, the Commission granted the Motion to Compel. The Commission restated that it allowed $23,000.00 in property taxes, which was the number presented by NWPS to the Commission at the hearing. NWPS was required to comply with the Commission's Order regarding this finding. On the question of whether the pipeline is an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A), the Commission decided to take that question under advisement.

At its May 8, 2001, meeting, the Commission considered whether the Aberdeen pipeline is an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A). The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 49-34A-1. The Commission voted to find the Aberdeen pipeline is not an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A). This statute provides as follows:

> [A]ny natural gas pipeline located entirely within the state that transports gas from a receipt point to one or more locations for customers other than the pipeline operator. However, the term does not apply if there is only one customer and the customer is a wholly-owned subsidiary of the pipeline operator, the customer is the parent

company of the pipeline operator, or the customer and the pipeline operator are wholly-owned subsidiaries of the same parent company. Further, the term does not apply to natural gas lines and appurtenant facilities used to gather gas from natural gas production facilities or sites and move the gas to an interconnecting transportation pipeline system[.]

The Aberdeen pipeline, owned and operated by Nekota Resources, Inc. (Nekota), transports gas solely for NEC, a subsidiary of NorthWestern Corporation. Nekota is also a subsidiary of NorthWestern Corporation. Thus, the pipeline falls within the exception found in the second sentence of the definition.

At its May 8, 2001, meeting, the Commission also voted to require Nekota to inform the Commission if the way it currently operates the Aberdeen pipeline changes in the future.

It is therefore

ORDERED, that the Aberdeen pipeline is not an intrastate natural gas pipeline as defined by SDCL 49-34A-1(9A); and it is

FURTHER ORDERED, that Nekota shall inform the Commission if the way it currently operates the Aberdeen pipeline changes in the future.

Dated at Pierre, South Dakota, this 11th day of May, 2001.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 5/14/01

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

JAMES A. BURG, Chairman

PAM NELSON, Commissioner