Public Service Commission
Receipt of Payment

Receipt# 6633

Received 8/4/2006 Check# 5090 for $19 05

Docket # PU-04-578

Subject Utility Valuation - pd by David H Sederquist

Prefile balance $1,600. Notify Mr. David Sparby

Mr. David Sparby
Northern States Power Company
414 Nicollet Mall
Minneapolis MN 55401

107 PU-04-578 Pages 1

Receipt# 6,633 $19 05

by Northern States Power Company

08/04/2006

APPROVED
DATE: 5-24-06

MOTION

May 24, 2006

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission bill Northern States Power Company for costs incurred to date in Case No. PU-04-578, Northern States Power Company, Natural Gas Rate Increase, Application.

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E. Wefald
Kevin Cramer

Executive Secretary
Illona A. Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www.psc.state.nd.us
e-mail ndpsc@state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

May 24, 2006

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

RE: Case No. PU-04-578
Northern States Power Company
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the May 24, 2006 Public Service Commission meeting for the expenses incurred to date in Case No. PU-04-578.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Admin Staff Officer
701-328-2401

Enc.

c: James P. Johnson
Northern States Power Co.
800 Nicollet Mall Ste 2900
Minneapolis MN 55401

Billing Statement

May 24, 2006

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

Expenses Incurred to Date:

Office of Administrative Hearings	$19.05

Amount Due:

Northern States Power Company	$19.05

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

OFFICE OF ADMINISTRATIVE HEARINGS

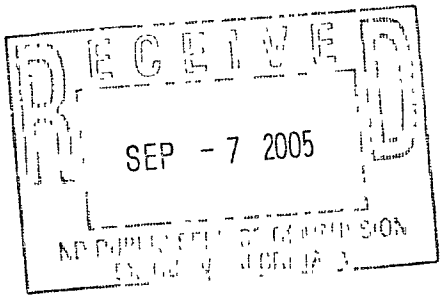
STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state nd us
www state nd.us/oah

September 6, 2005

Mr. William W. Binek
Hearings Administrator
Public Service Commission
600 East Boulevard Avenue, Dept.408
Bismarck, ND 58505-0480



Re: Northern States Power Co.
Natural Gas Rate Increase Application
Case No. PU-04-578
OAH File No. 20040466

Dear Mr. Binek·

On September 1, 2005, you informed me that the hearing on the Northern States Power Co. natural gas rate increase (Case No. PU-04-578) had been settled and the compliance tariffs filed and approved. Accordingly, I am closing our file on this matter and returning that portion of the record I have in my possession to you. Please find enclosed copies of documents that have been transmitted to us, as well as originals and copies of documents received while the file was in our possession, for filing with the official agency record of this matter.

Thank you for your attention to this matter.

Sincerely,

Allen C Hoberg
Administrative Law Judge

ACH/eap

Encl.

cc: Mr. Jim Johnson
Northern States Power Co.
Mr. David Sederquist
Northern States Power Co.

105 PU-04-578 Pages 1

Letter closing ALJ's file

by Office of Administrative Hearings
09/07/2005 CC Comm Legal PUD (4) Mike

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

June 29, 2005

Dave Sederquist
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

Dear Mr. Sederquist.

On June 29, 2005, the Commission approved Northern States Power Company's gas rates filed in compliance with the Commission's June 1, 2005 order in Case No. PU-04-578.

Sincerely,

Sharon Helbling
Public Utilities Division

sdh

Enclosures

104 PU-04-578 Pages 1

Letter re approval of Compliance Rates

by Public Service Commission
06/30/2005 CC Comm Legal PUD (4) Mike

APPROVED
DATE: 6-29-05
KMF

MOTION

June 29, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission approve Northern States Power Company's Compliance Rates, to be effective with services rendered on or after July 1, 2005, in Northern States Power Company's Natural Gas Rate Increase application, Case No PU-04-578

PJF/sdh

Public Service Commission
Receipt of Payment

Receipt# 6290

Received 6/23/2005 Check# 111853 for $500 84

Docket # PU-04-578

Subject Utility Valuation

Prefile balance $3,200. Notify Mr. David Sparby

Mr David Sparby
Northern States Power Company
414 Nicollet Mall
Minneapolis MN 55401

102 PU-04-578 Pages 1

Receipt# 6,290 $500 84

by Northern States Power Company

06/23/2005

Public Service Commission
State of North Dakota

RECEIVED
JUN 20 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

COMMISSIONERS
Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

June 8, 2005

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

RECEIVED
2005
COMMISSION

Larkin & Associates, PLLC
Certified Public Accountants
15728 Farmington Road
Livonia MI 48154

Re: Contract No. PU-497-05
Case No. PU-04-578
NSP-ND Gas Cost of Capital

Our records indicate that all services required under the terms of the contract for professional services in the above case have been performed. Accordingly, we are preparing to close out the contract.

If you have any outstanding claims for service against this contract, please inform us immediately.

If you don't have any outstanding claims, please return this letter in the enclosed envelope with a note at the bottom stating so and a signature.

Thanks.

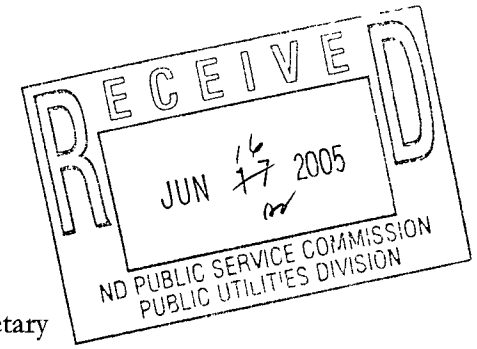
Sincerely,

Gloria Geiger
Administrative Staff Officer
701-328-2401

We have no outstanding claim under this contract. We have been paid in full.
Larkin & Associates PLLC
by Hugh Larkin Jr

Pages 1
101 PU-04-578
No outstanding claims/paid in full
by Larkin & Associates PLLC
06/20/2005 CC Comm Legal PUD (4) Mike

Xcel Energy



2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

June 16, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE. GAS RATE TARIFF COMPLIANCE FILING
CASE NO. PU-400-04-578

Dear Ms. Jeffcoat-Sacco:

In his review of the natural gas compliance tariffs Xcel Energy submitted this week, Jerry Lein noticed a couple of typos on our compliance tariffs. So we're submitting this revised set.

Most importantly, Section 6, sheet 3 was corrected so the returned check charge reflects the $15 agreed to in the Settlement. The other five tariff sheet changes to Section 5 were only aesthetic changes (to the tariff title)·

Our Titles for Rate 407 were not consistent across all sheets

- Sheet 5-8 added "Large Commercial" in front of "Interruptible Transportation Service"
- Sheet 5-10 1 added "Large Commercial" in front of "Interruptible Transportation Service"
- Sheet 5-10 2 added "Large Commercial" in front of "Interruptible Transportation Service

Our Titles for Rate 415 were not consistent across all sheets

- Sheet 5-13 2 added "Large Commercial" in front of "Firm Transportation Service"
- Sheet 5-13 3 added "Large Commercial" in front of "Firm Transportation Service"

Returned Check Charge

- Sheet 6-11 changed $25 to $15 in returned check charge section

Enclosed here is an original and one copy of a complete set of tariffs.

Let me know if you have any other questions or comments.

Sincerely

David H. Sederquist

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION & FINANCE
NORTHERN STATES POWER CO. D/B/A XCEL ENERGY

Enclosures

100 PU-04-578 Pages 30

Revised compliance tariff filing

by Northern States Power Company by

06/16/2005 CC Comm Legal PUD (4) Mike

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO 2

TABLE OF CONTENTS

Section No 1
2nd Revised Sheet No 1

Section	Item	Sheet No
TITLE SHEET		Title Sheet
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SECTION 2	**CONTACT LIST**	2-1
SECTION 3	**INDEX OF COMPANY'S SERVICE AREA**	3-1
SECTION 4	**TECHNICAL AND SPECIAL TERMS**	
	Definition of Symbols	4-1
	Rate Codes	4-2
SECTION 5	**RATE SCHEDULES**	
	Residential Service	5-1
	Commercial and Industrial Service	5-2
	Small Interruptible Service	5-3
	Large Interruptible Service	5-5
	Interruptible Contract Service	5-7
	Interruptible Transportation Service	5-8
	Emergency Gas Service for Interruptible Customers	5-11
	Firm Transportation Service	5-13 D
	Propane Service (Non-Regulated)	5-18
	RIDERS	
	Cost of Gas Rider	5-19
	Surcharge Rider	5-21
	Daily Balancing Service Rider	5-22
	Limited Firm Service Rider	5-26

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

(Continued on Sheet No 1-2)

Date Filed 11-02-04
By Kent T Larson
Vice President of Jurisdictional Relations
Effective Date 07-01-05
Case No PU-400-04-578
Order Date 06-01-05

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO. 2

TABLE OF CONTENTS - SUPPLEMENT
RATE SHEET CROSS REFERENCE TABLE

Section No 1
1st Revised Sheet No A

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

Date Filed 11-02-04
Case No PU-400-04-578

By Kent T Larson
Vice President of Jurisdictional Relations

Effective Date 07-01-05
Order Date 06-01-05

F \RA\Rates\Current\Nd_gas\NG_1_A_r01 DOC

TABLE OF CONTENTS - SUPPLEMENT
RATE SHEET CROSS REFERENCE TABLE (Continued)

Section No 1
1st Revised Sheet No B

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO 2

TABLE OF CONTENTS - SUPPLEMENT Section No 1
RATE SHEET CROSS REFERENCE TABLE (Continued) 1st Revised Sheet No C

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

Date Filed 11-02-04 By Kent T Larson Effective Date 07-01-05
Vice President of Jurisdictional Relations
Case No PU-400-04-578 Order Date 06-01-05

F \RA\Rates\Current\Nd_gas\NG_1_C_r01 DOC

CONTACT LIST

Section No 2
2nd Revised Sheet No 1

Listed below is the name, title, address, and telephone numbers of Company personnel to be contacted in connection with

All Matters Relating to Rates and Rules	Kent T Larson	T
	Vice President of Jurisdictional Relations	T
	Northern States Power Company, d/b/a Xcel Energy	T
	414 Nicollet Mall	T
	Minneapolis, MN 55401	T
	Telephone No 1-800-328-8226	T
Gas Emergencies and Outages	Telephone No (800) 895 2999	T
24-Hour Residential Customer Service	Telephone No (800) 895-4999	T
Business Solutions Center	Telephone No (800) 481-4700	T
(Business Customer Service)		T
TDD/TYY (Hearing Impaired Services)	Telephone No (800) 895-4949	N
Internet Address	www xcelenergy com	N

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

TECHNICAL AND SPECIAL TERMS (Continued)

Section No 4
2nd Revised Sheet No 2

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

RESIDENTIAL SERVICE Section No 5
RATE CODE 401 4th Revised Sheet No 1

AVAILABILITY
This rate is available to any residential customer for domestic use of natural gas service T

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

RATE

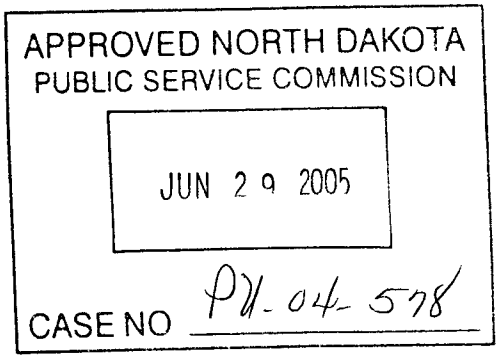
Delivery Services Charge per Month	$15 69	TC D
Cost of Gas Charge per Therm	Determined Monthly	C

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

MONTHLY MINIMUM CHARGE
Delivery Services Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due



COMMERCIAL AND INDUSTRIAL SERVICE Section No 5
RATE CODE 403 AND 410 4th Revised Sheet No 2

AVAILABILITY
This rate is available to any commercial and industrial customer for general use of natural gas service T

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

RATE

Basic Service Charge per Month	$20 00	C
Distribution Charge per Therm	$0 10710	C
Cost of Gas Charge per Therm	Determined Monthly	

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 2 9 2005
CASE NO PU-04-578

SMALL INTERRUPTIBLE SERVICE Section No 5
RATE CODE 404 3rd Revised Sheet No 3

AVAILABILITY
This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are less than 2,000 Therms, and who will agree T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

RATE

Basic Service Charge per Month	$75 00
Distribution Charge per Therm	$0 07740 C
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

(Continued on Sheet No 5-4)

SMALL INTERRUPTIBLE SERVICE (Continued) Section No 5
RATE CODE 404 3rd Revised Sheet No 4

MONTHLY MINIMUM CHARGE
Basic Service Charge

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 2 9 2005
CASE NO PU-04-578

LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No 5
5th Revised Sheet No 5

AVAILABILITY
This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$275 00
Distribution Charge per Therm	$0 04632 C
Cost of Gas Charge per Therm	Determined Monthly

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 2 9 2005
CASE NO PU-04-578

(Continued on Sheet No 5-6)

LARGE INTERRUPTIBLE SERVICE (Continued) Section No 5
RATE CODE 405 3rd Revised Sheet No 6

Flexible Distribution Charge
Customers are normally served on the fixed rate but will be placed on the flexible rate if, for pricing reasons, the flexible rate is necessary to compete with a non-gas alternate energy supply/service Company and customer will agree to a price between $0 00600 and $0 04390 per Therm Unless otherwise agreed, a five day notice of price change shall be provided If Company and customer cannot agree to a flexible distribution charge and customer nonetheless uses gas, then customer shall be charged the maximum allowable flexible distribution charge

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late paym ent charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE Section No 5
RATE CODE 407 3rd Revised Sheet No 8 T

AVAILABILITY

This rate is available on an interruptible basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station, whose maximum daily requirements are more than 2,000 Therms, and who agrees T

1 To curtail use of gas within one hour after Company notification,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment in the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Delivery of gas hereunder shall be subject to curtailment whenever requested by Company Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption i adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month $300 00

	Minimum	Maximum
Distribution Charge per Therm	$0 0060	$0 04390

Unless otherwise agreed to between customer and Company, five days notice of price change shall be provided

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

(Continued on Sheet No 5-9)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
3rd Revised Sheet No 10

MONTHLY MINIMUM CHARGE
Unless otherwise agreed to in a negotiated service contract, the monthly minimum is the Basic Service Charge

NOMINATIONS
Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6 00 p m
Intra-day 1	10 00 a m
Intra-day 2	5 00 p m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS
Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0 05 per Therm However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

(Continued on Sheet No 5-10 1)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10 1

T

MONTHLY UNDERTAKE / OVERTAKE CHARGE

Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively

C

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1 00 + ITC	MIP * 1 00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0 98 + FTC
>5% - 10%	MIP * 1 10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1 30 + ITC	MIP * 0 70 + FTC
>20%	MIP * 1 40 + ITC	MIP * 0 60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis

C

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE

A 1% late payment charge will be added to the unpaid balance on date due

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 2 9 2005
CASE NO PU-04-578

(Continued on Sheet No 5-10 2)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE Section No 5 T
(Continued) 2nd Revised Sheet No 10 2
RATE CODE 407

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers Rules and regulations defining Company's obligation are set out in Section 6 of this rate book

ADDITIONAL FACILITIES

The cost of any new facilities required to provide service under this rate shall be borne by the customer

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located Company may refuse to accept delivery of gas that does not meet this quality standard T

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

EMERGENCY GAS SERVICE FOR INTERRUPTIBLE CUSTOMERS

Section No 5
2nd Revised Sheet No 11

AVAILABILITY

This rate is available to an interruptible customer for supply of emergency gas during periods of curtailment when a customer is unable to operate its standby facilities for causes not reasonably within its control T T

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

RATE D

Operational Cost per Therm	$0 13468	N
Cost of Propane Gas per Therm	$0 71415	N
Total Cost per Therm	$0 84883	N

DETERMINATION OF COST OF GAS N

If the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference N N

DISTRIBUTION CHARGE

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate C

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

SPECIAL TERMS AND CONDITIONS

1 Emergency gas service will be available providing that
   a A customer has advised the Company that it is experiencing an emergency and, in the opinion of Company, it is an emergency resulting from causes not reasonably within customer's control T
   Failure of the customer to take normal precautions for providing its alternate fuel supply will not be considered an emergency T
   b Customer shall make arrangements with Company specifying the reason for said service and the probable duration of the emergency
   c Such service will not adversely affect firm service to any customer

2 Customer receiving emergency service shall agree in writing as to the quantity of gas to be supplied and the duration of the service Gas used prior to the effective date and time agreed to will be billed under the provision "Additional Charge for Use of Gas During Curtailment" of the applicable interruptible rate T

3 The Company reserves the right to refuse or curtail the supply of emergency gas service if its supply of gas is not adequate to furnish such service

4 All other provisions of the interruptible service rate schedules not in conflict herewith shall apply

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

GAS YARD LIGHTING SERVICE (CLOSED)
RATE CODE 408

Section No 5
2nd Revised Sheet No 12

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO. 2

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE Section No 5
RATE CODE 415 3rd Revised Sheet No 13

AVAILABILITY
This rate is available on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms T

CHARACTER OF SERVICE
Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Customer Charge per Month	$300 00	
	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0 69600
Energy Charge per Therm	$0 00898	$0 03471

Unless otherwise agreed to, a five-day notice of any change in the energy charge shall be provided T

RESOURCE ADJUSTMENT
Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider The Company will revise the surcharge annually on the effective date of the True-up factor change

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

(Continued on Sheet No 5-13 1)

Date Filed 11-02-04 By Kent T Larson Vice President of Jurisdictional Relations Effective Date 07-01-05
Case No PU-400-04-578 Order Date 06-01-05

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE
(Continued)
RATE CODE 415

Section No 5
1st Revised Sheet No 13 2

T

NOMINATIONS

Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6 00 p m
Intra-day 1	10 00 a m
Intra-day 2	5 00 p m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system

C

IMBALANCE PROVISIONS

Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0 05 per Therm However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
JUN 2 0 2005
CASE NO PU-04-578

(Continued on Sheet No 5-13 3)

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE
(Continued)
RATE CODE 415

Section No 5
1st Revised Sheet No 13 3

T

C

MONTHLY UNDERTAKE / OVERTAKE CHARGE

Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1 00 + ITC	MIP * 1 00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0 98 + FTC
>5% - 10%	MIP * 1 10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1 30 + ITC	MIP * 0 70 + FTC
>20%	MIP * 1 40 + ITC	MIP * 0 60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis

C

LATE PAYMENT CHARGE

A 1% late payment charge will be added to the unpaid balance on due date

SURCHARGE

Bills are subject to the applicable surcharge provided for in the Surcharge Rider

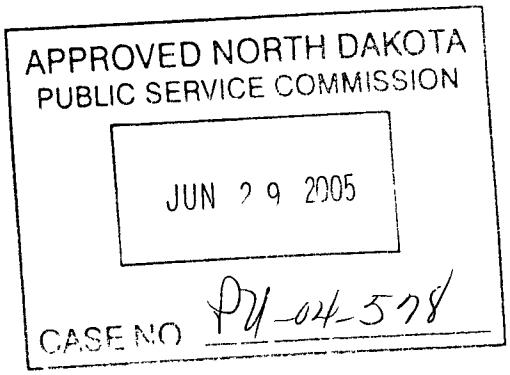
APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 2 9 2005
CASE NO PU-04-578

(Continued on Sheet No 5-13 4)

STANDBY SERVICE RIDER

Section No 5
2nd Revised Sheet No 24

CANCELED



(Continued on Sheet No 5-25)

STANDBY SERVICE RIDER (Continued)

Section No 5
Original Sheet No 25

CANCELED

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO PU-04-578

LIMITED FIRM SERVICE RIDER

Section No 5
2nd Revised Sheet No 26

AVAILABILITY
This rate is available to any Interruptible or Interruptible Transportation Service customer who, when subject to interruption or curtailment, desires to supplement its service by reserving a specified number of days of firm gas service in a Limited Firm Service Agreement with Company Limited Firm Service will be restricted to 10 days for Small Volume customers and 15 days for Large Volume customers during the term of agreement T

CHARACTER OF SERVICE
Company in its sole discretion may decline to enter into Limited Firm Service Agreements or limit the days of availability and shall consider the Company's estimate of its distribution capacity and stored gas availability to provide Limited Firm Service

CURTAILMENT
If the Company's system operations require curtailment of firm service, service hereunder will be curtailed before all other firm service, and customer will be credited a portion of the Availability Charge based on the days of curtailed firm service and that contracted for

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

COST OF PROPANE GAS RATE
Availability Charge As specified in the Limited Firm Service Agreement between customer and Company D

Operational Cost per Therm	$0 13468	N
Cost of Propane Gas per Therm	$0 71415	N
Total Cost per Therm	$0 84883	N

DETERMINATION OF COST OF GAS
If the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference C C

DISTRIBUTION CHARGE N
All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate N

(Continued on Sheet No 5-27)

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

Date Filed 11-02-04
By Kent T Larson
Vice President of Jurisdictional Relations
Effective Date 07-01-05
Case No PU-400-04-578
Order Date 06-01-05

F \RA\Rates\Current\Nd_gas\Ng_5_26_r02 doc

SECTION 1 GENERAL SERVICE RULES

1.1 APPLICATION FOR SERVICE

A party desiring gas service must make application to the Company before commencing the use of the Company's service The Company reserves the right to require a signed application or written contract for service to be furnished All applications and contracts for service must be made in the legal name of the party desiring the service The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account Any person who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used

When required by governmental authority, a customer desiring new service or expanded service first must make application for and receive written approval from the Company

Subject to its rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service The customer will be responsible for payment of all service furnished through the date of discontinuance

1.2 SERVICE PROCESSING CHARGE

The Company will charge $15 00 for the initial establishment or the reestablishment of service for each customer If any combination of gas or electric services requested by a customer and furnished by the Company is established or reestablished at the same time and location, only one $15 00 charge will be made C C

If a customer requests reestablishment of service at a location where the same customer discontinued the same service within the preceding 12 month period, an additional reconnection fee will be assessed equal to the sum of the monthly minimum charges applicable during the period service was not taken N | N

1 3 ACCESS TO CUSTOMER'S PREMISES

Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incident to the service

1.4 CONTINUITY OF SERVICE

The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same

(Continued on Sheet No 6-4)

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

3.6 BILL DATE DUE

Bills are due and payable upon presentation For purposes of applying the late payment charge, the date due shown on the customer's bill shall be

Class	Date Due
Interruptible	Minimum of 10 working days after bill mailing date
All Other Classes	Next scheduled billing date minus four working days

3 7 ESTIMATED BILLS

An estimated bill will be rendered if it is impractical for the Company to read the meter or if customer fails to supply a meter reading form in time for the billing operation, or in cases of emergency An adjustment, if any, will be made in the bill based on the next meter reading

3.8 BILLING ADJUSTMENTS

In the event of a meter or billing error, as defined by the Public Service Commission's rules, the Company shall recalculate the bills for service during the period of the error and make adjustment of bills in accordance with the rules prescribed by the Commission If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10 00

3.9 RETURNED CHECK CHARGE

There shall be a charge of $15 00 for any check or draft submitted to the Company for payment that is dishonored or returned by the financial institution on which it is drawn T

3 10 ACCOUNT HISTORY CHARGE

There shall be a charge of $0 50 per account to the authorized requesting party for providing account history when such request involves 10 or more accounts, regardless of the type of account or number of meters An authorized requesting party may be the customer, a person authorized by the customer, or a person authorized by law to receive the requested information

APPROVED NORTH D-
PUBLIC SERVICE CO-
JUN 29 2005
CASE NO. PU-04-578

5 2 MAIN EXTENSIONS

The Company will extend, enlarge, or change its gas mains or other facilities for supplying gas service when the anticipated revenue from the sale of additional service to result there from is such as to justify the expenditure When the expenditure is not so justified, the extension, enlargement, or change of facilities will be made only if the customer, at the Company's option

A Pays in advance to the Company in cash for the additional installation costs for excess footage as required by the Company's current footage costs or by promissory note acceptable to the Company, the portion of the capital expenditure not justified by the anticipated annual revenue with provision for refund of all or part of such payment, C

B Agrees to pay a special monthly charge,

C Agrees to pay annually a specified minimum charge, or

D Agrees to a combination of the above methods

In addition, a non-refundable payment in advance must be made covering the specified additional cost of any unusual construction

For each additional customer served directly from the main extension within five years from the date of its completion, the person who made advance payment will receive refunds based on the revenue to be received from the additional customers served from the extension and the costs required to serve such customers The total of such refunds will in no event exceed the total advance payment No refunds will be made for additional customers served by additional main extensions connected at any point to the first customer's original extension

For trailer parks, the Company will only extend its gas main to a delivery point at a permanent structure which houses facilities such as offices or laundry facilities It shall be the trailer park owner's responsibility to extend the distribution system to individual trailer sites D

(Continued on Sheet No 6-19)

APPROVED NORTH DA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

5.3 WINTER CONSTRUCTION

When the service or main is installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30 or because the customer's property, or the streets leading thereto, are not ready to receive the service pipe or gas main by such date, such work will be subject to a winter construction charge when winter conditions of ground frost and/or snow exist, for the entire length of underground service or gas main installed Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install gas main or gas service pipe during the winter season The charges immediately below apply to frost depths of 18" or less At greater frost depths, the Company will individually determine the job cost The Company reserves the right to charge for any unusual winter construction expenses All winter construction charges are non-refundable and are in addition to any normal construction charges C

Winter Construction Charge		
Excavation		$400 per excavating unit
Main & Service Extensions	4 Inch or Under Pipe	$3 00 per foot
	Over 4 Inch Pipe	Determined Individually

C

5 4 LIMITATIONS ON THE AVAILABILITY OF GAS

New and existing customers requiring service for new or increased firm or interruptible gas loads must make an application for such service The Company shall apply the applicable limitations set forth in this section in determining whether to approve an application When supplies of gas and distribution capacity are adequate, Company will authorize connection of qualifying customers in the order that their application is received When an applicant is one for which a main extension is required, the application will be held until the main extension is approved, at which time it shall be processed the same as an on-main customer

A. New and Existing Firm Customers

1 New customers will be added in accordance with Section 5, EXTENSION RULES, of the General Rules and Regulations

2 Existing loads, except as noted below, may be increased and new loads added only with the approval of the Company based upon the adequacy of gas supplies and gas distribution capacity

3 Increases in existing loads for non-heating requirements not in excess of 0 5 Therm per hour do not require Company approval in accordance with Section 1 1, APPLICATION FOR SERVICE, of the General Rules and Regulations

(Continued on Sheet No 6-20)

APPROVED NORTH DAKOTA PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

5.5 SERVICE CONNECTIONS (Continued)

In addition, the Company will, at its own expense for all customers, furnish and install piping for a distance not to exceed five feet for

A Indoor Metering
From the service to the meter header or meter yoke

B Outdoor Metering
From the end of the horizontal service pipe to the outside of the customer's building wall

If this distance exceeds five feet in length, the Company will extend the piping if the customer will share the cost based on the Company's current footage costs C

5.6 TEMPORARY SERVICE D

The following special requirement is prescribed to govern temporary service

A customer taking temporary service (less than five years) will pay the rate applicable to the class of service rendered and will pay in advance the Company's specified cost, figured on a time and material basis, of the installation and removal of the facilities, including the meter required to furnish the desired service, less the salvage value of such facilities

APPROVED NORTH DAKOTA
PUBLIC SERVICE COMMISSION
JUN 29 2005
CASE NO. PU-04-578

Public Service Commission
State of North Dakota

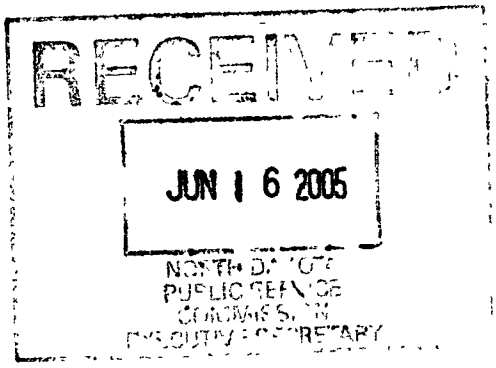
COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

June 16, 2005



Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 East Blvd. Avenue, Dept. 408
Bismarck, ND 58505-0480

Re: Case No. PU-04-578
Northern States Power Company
Natural Gas Rate Increase
Application

Dear Ms. Jeffcoat-Sacco:

Enclosed please find the original and seven copies of the Staff Response to Compliance Filing, in the above referenced case.

Sincerely,

William W. Binek
Chief Counsel

Enclosure

c Jim Johnson, Northern States Power Co
Dave Sederquist, Northern States Power Co

99 PU-04-578 Pages 1

Cover letter re Staff Response to Compliance Filing
by Public Service Commission
06/16/2005 CC Comm Legal PUD (4) Mike

RECEIVED
JUN 16 2005
NORTH DAKOTA
PUBLIC SERVICE

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

STAFF RESPONSE TO COMPLIANCE FILING
June 16, 2005

On June 13, 2005, Northern States Power Company d/b a Xcel Energy (NSP) filed tariff changes to comply with the Order of the Commission dated June 1, 2005. The Commission's Order adopted option B of a Settlement Agreement permitting NSP to implement a rate change sufficient to provide a total annual revenue increase of approximately $745,000 effective for service rendered on or after June 1, 2005. NSP's compliance tariffs provide a projected total annual revenue increase of $745,376. NSP requests an effective date of July 1, 2005.

As specified in the approved Settlement Agreement Option B, NSP's proposed compliance tariffs would increase projected total gas and distribution charge revenue from the residential class by 1.7% (0.4% over interim level) while increasing projected revenue from the commercial/industrial and small interruptible classes by 0.7% (-0.3% and -0.1% respectively from interim) and large industrial by 0.4% (-0.1% from interim).

As specified in the approved Settlement Agreement Option B, NSP's proposed compliance tariffs would combine the 1.7% residential revenue increase with the previous $5.50 monthly fixed customer charge and the previous $1.248 volumetric charge per dekatherm into a single monthly distribution charge fixed at $15.69 per customer. A previously approved surcharge of $0.0368 per dekatherm for recovering manufactured gas plant cleanup costs will remain in effect through an amortization period ending September 2009. For a typical residential customer with averaged annual consumption of approximately 7.5 dekatherms per month, NSP calculates this increase would average $0.83 per month. For averaged annual consumption of 10 dekatherms per month, the effect would be a decrease averaging $2.29 per month.

As specified in schedule C to the Settlement Agreement, the Commercial / Industrial base rate has been increased from $14.00 to $20.00 per month. Other base rates remain unchanged.

NSP's compliance tariff includes various other rate design and language changes that were included in the initial filing and not challenged by staff. The tariff also includes NSP's supplemental filing of new language (section 6, sheet 3) requiring customers that disconnect and then request reconnection within 12 months to

pay the customer charges for the months they were disconnected. MDU has similar provisions in its tariff.

Staff found one error in the compliance filing. The returned check charge is specified as $25 when it should have been $15. NSP has agreed to file a correction. NSP is also working on a bill message and rate folder for the July billing cycle and will provide a copy as soon as it is done.

With correction of the returned check charge staff believes that NSP's compliance filing will satisfy the Commission's Order.

William W. Binek
Chief Counsel

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **16th day of June, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes by first class postage, fully prepaid, securely sealed and each containing a photocopy of:

Staff Response to Compliance Filing

The envelopes were addressed as follows:

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747

Kent T Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Minneapolis MN 55401

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis MN 55401

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sandra L Scott

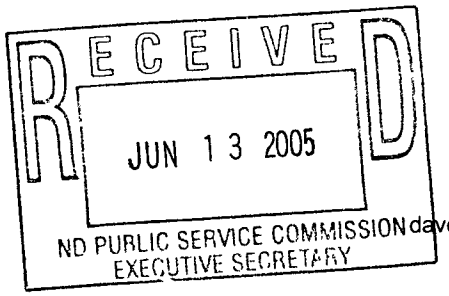
Subscribed and sworn to before me
this **16th day of June, 2005**.

Shelly A Bauske
Notary Public

SEAL

SHELLY A BAUSKE
Notary Public
State of North Dakota
My Commission Expires July 22, 2010





2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

June 13, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: GAS RATE TARIFF COMPLIANCE FILING
CASE NO. PU-400-04-578

Dear Ms. Jeffcoat-Sacco:

Enclosed are an original and seven copies of our natural gas rate tariffs as recently approved by the Commission. On November 2, 2004 the Company filed a petition for changes to our natural gas rates in North Dakota. The attached tariff reflects changes authorized by the Commission's June 1, 2005 Order.

An electronic version of this letter and the tariff sheets was e-mailed to you this afternoon.

Red-line versions of the tariff language changes are included in the original rate application, with only the Settlement rate changes reflected here being different from the application. The red-line version of Sheet No. 3 in Section 6 was filed separately with the Commission on April 8, 2005, per provisions in the Settlement Agreement.

North Dakota Electric Rates:

Tariff Section 1
Sheet No. 1, revision 2
Sheet No. A –canceled
Sheet No. B –canceled
Sheet No. C –canceled

Tariff Section 2
Sheet No. 1, revision 2

Tariff Section 4
Sheet No. 2 –canceled

96 PU-04-578 Pages 2
Cover letter re Compliance Tariff
by Northern States Power Company
06/13/2005 CC Comm Legal PUD (4) Mike

Tariff Section 5

Sheet No. 1, revision 4
Sheet No. 2, revision 4
Sheet No. 3, revision 3
Sheet No. 4, revision 3
Sheet No. 5, revision 5
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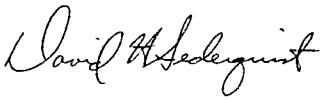
Tariff Section 6

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Sheet No. 22, revision 1

The Company is taking steps to effectuate these tariffs on July 1, 2005.

Let me know if you have any other questions or comments regarding these tariffs.

Sincerely,



DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION & FINANCE
NORTHERN STATES POWER CO. D/B/A XCEL ENERGY

Enclosures

RECEIVED
JUN 13 2005
ND PUBLIC SERVICE COMMISSION

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO 2

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2nd Revised Sheet No 1

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Date Filed 11-02-04 By Kent T Larson
Vice President of Jurisdictional Relations
Effective Date 07-01-05

Case No PU-400-04-578 Order Date 06-01-05

95 PU-04-578 Pages 29
Compliance Tariff
by Northern States Power Company by
06/13/2005 CC Comm Legal PUD (4) Mike

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CANCELED

CONTACT LIST

Section No 2
2nd Revised Sheet No 1

Listed below is the name, title, address, and telephone numbers of Company personnel to be contacted in connection with

All Matters Relating to Rates and Rules	Kent T Larson	T
	Vice President of Jurisdictional Relations	T
	Northern States Power Company, d/b/a Xcel Energy	T
	414 Nicollet Mall	T
	Minneapolis, MN 55401	T
	Telephone No 1-800-328-8226	T
Gas Emergencies and Outages	Telephone No (800) 895 2999	T
24-Hour Residential Customer Service	Telephone No (800) 895-4999	T
Business Solutions Center	Telephone No (800) 481-4700	T
(Business Customer Service)		T
TDD/TYY (Hearing Impaired Services)	Telephone No (800) 895-4949	N
Internet Address	www xcelenergy com	N

TECHNICAL AND SPECIAL TERMS (Continued)

Section No 4
2nd Revised Sheet No 2

CANCELED

RESIDENTIAL SERVICE Section No 5
RATE CODE 401 4th Revised Sheet No 1

AVAILABILITY
This rate is available to any residential customer for domestic use of natural gas service T

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

RATE

Delivery Services Charge per Month	$15 69	TC D
Cost of Gas Charge per Therm	Determined Monthly	C

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

MONTHLY MINIMUM CHARGE
Delivery Services Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

COMMERCIAL AND INDUSTRIAL SERVICE Section No 5
RATE CODE 403 AND 410 4th Revised Sheet No 2

AVAILABILITY
This rate is available to any commercial and industrial customer for general use of natural gas service T

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a T
base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

RATE

Basic Service Charge per Month	$20 00	C
Distribution Charge per Therm	$0 10710	C
Cost of Gas Charge per Therm	Determined Monthly	

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

SMALL INTERRUPTIBLE SERVICE Section No 5
RATE CODE 404 3rd Revised Sheet No 3

AVAILABILITY
This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are less than 2,000 Therms, and who will agree T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$75 00
Distribution Charge per Therm	$0 07740 C
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

(Continued on Sheet No 5-4)

MONTHLY MINIMUM CHARGE
Basic Service Charge

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No 5
5th Revised Sheet No 5

AVAILABILITY
This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$275 00
Distribution Charge per Therm	$0 04632 C
Cost of Gas Charge per Therm	Determined Monthly

(Continued on Sheet No 5-6)

Flexible Distribution Charge
Customers are normally served on the fixed rate but will be placed on the flexible rate if, for pricing reasons, the flexible rate is necessary to compete with a non-gas alternate energy supply/service Company and customer will agree to a price between $0 00600 and $0 04390 per Therm Unless otherwise agreed, a five day notice of price change shall be provided If Company and customer cannot agree to a flexible distribution charge and customer nonetheless uses gas, then customer shall be charged the maximum allowable flexible distribution charge

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late paym ent charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

INTERRUPTIBLE TRANSPORTATION SERVICE Section No 5
RATE CODE 407 3rd Revised Sheet No 8

AVAILABILITY

This rate is available on an interruptible basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station, whose maximum daily requirements are more than 2,000 Therms, and who agrees T

1 To curtail use of gas within one hour after Company notification,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment in the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Delivery of gas hereunder shall be subject to curtailment whenever requested by Company Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption i adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month $300 00

	Minimum	Maximum
Distribution Charge per Therm	$0 0060	$0 04390

Unless otherwise agreed to between customer and Company, five days notice of price change shall be provided

(Continued on Sheet No 5-9)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE Section No 5
(Continued) 3rd Revised Sheet No 10
RATE CODE 407

MONTHLY MINIMUM CHARGE
Unless otherwise agreed to in a negotiated service contract, the monthly minimum is the Basic Service Charge

NOMINATIONS
Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6 00 p m
Intra-day 1	10 00 a m
Intra-day 2	5 00 p m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS
Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0 05 per Therm However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month

(Continued on Sheet No 5-10 1)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10 1

MONTHLY UNDERTAKE / OVERTAKE CHARGE

Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively C

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1 00 + ITC	MIP * 1 00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0 98 + FTC
>5% - 10%	MIP * 1 10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1 30 + ITC	MIP * 0 70 + FTC
>20%	MIP * 1 40 + ITC	MIP * 0 60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis C

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE

A 1% late payment charge will be added to the unpaid balance on date due

(Continued on Sheet No 5-10 2)

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers Rules and regulations defining Company's obligation are set out in Section 6 of this rate book

ADDITIONAL FACILITIES

The cost of any new facilities required to provide service under this rate shall be borne by the customer

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located Company may refuse to accept delivery of gas that does not meet this quality standard T

EMERGENCY GAS SERVICE FOR INTERRUPTIBLE CUSTOMERS

Section No 5
2nd Revised Sheet No 11

AVAILABILITY

This rate is available to an interruptible customer for supply of emergency gas during periods of curtailment when a customer is unable to operate its standby facilities for causes not reasonably within its control T T

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

RATE D

Operational Cost per Therm	$0 13468	N
Cost of Propane Gas per Therm	$0 71415	N
Total Cost per Therm	$0 84883	N

DETERMINATION OF COST OF GAS N

If the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference N

DISTRIBUTION CHARGE

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate C

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

SPECIAL TERMS AND CONDITIONS

1 Emergency gas service will be available providing that

a A customer has advised the Company that it is experiencing an emergency and, in the opinion of Company, it is an emergency resulting from causes not reasonably within customer's control T
Failure of the customer to take normal precautions for providing its alternate fuel supply will not be considered an emergency T

b Customer shall make arrangements with Company specifying the reason for said service and the probable duration of the emergency

c Such service will not adversely affect firm service to any customer

2 Customer receiving emergency service shall agree in writing as to the quantity of gas to be supplied and the duration of the service Gas used prior to the effective date and time agreed to will be billed under the provision "Additional Charge for Use of Gas During Curtailment" of the applicable interruptible rate T

3 The Company reserves the right to refuse or curtail the supply of emergency gas service if its supply of gas is not adequate to furnish such service

4 All other provisions of the interruptible service rate schedules not in conflict herewith shall apply

GAS YARD LIGHTING SERVICE (CLOSED)
RATE CODE 408

Section No 5
2nd Revised Sheet No 12

CANCELED

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE Section No 5
RATE CODE 415 3rd Revised Sheet No 13

AVAILABILITY
This rate is available on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms T

CHARACTER OF SERVICE
Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE
Customer Charge per Month $300 00

	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0 69600
Energy Charge per Therm	$0 00898	$0 03471

Unless otherwise agreed to, a five-day notice of any change in the energy charge shall be provided T

RESOURCE ADJUSTMENT
Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider The Company will revise the surcharge annually on the effective date of the True-up factor change

(Continued on Sheet No 5-13 1)

FIRM TRANSPORTATION SERVICE (Continued) Section No 5
RATE CODE 415 1st Revised Sheet No 13 2

NOMINATIONS

Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6 00 p m
Intra-day 1	10 00 a m
Intra-day 2	5 00 p m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS

Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0 05 per Therm However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month

(Continued on Sheet No 5-13 3)

FIRM TRANSPORTATION SERVICE (Continued) Section No 5
RATE CODE 415 1st Revised Sheet No 13 3

MONTHLY UNDERTAKE / OVERTAKE CHARGE

Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1 00 + ITC	MIP * 1 00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0 98 + FTC
>5% - 10%	MIP * 1 10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1 30 + ITC	MIP * 0 70 + FTC
>20%	MIP * 1 40 + ITC	MIP * 0 60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis

LATE PAYMENT CHARGE

A 1% late payment charge will be added to the unpaid balance on due date

SURCHARGE

Bills are subject to the applicable surcharge provided for in the Surcharge Rider

(Continued on Sheet No 5-13 4)

STANDBY SERVICE RIDER

Section No 5
2nd Revised Sheet No 24

CANCELED

(Continued on Sheet No 5-25)

STANDBY SERVICE RIDER (Continued)

Section No 5
Original Sheet No 25

CANCELED

LIMITED FIRM SERVICE RIDER

Section No 5
2nd Revised Sheet No 26

AVAILABILITY

This rate is available to any Interruptible or Interruptible Transportation Service customer who, when subject to interruption or curtailment, desires to supplement its service by reserving a specified number of days of firm gas service in a Limited Firm Service Agreement with Company Limited Firm Service will be restricted to 10 days for Small Volume customers and 15 days for Large Volume customers during the term of agreement T

CHARACTER OF SERVICE

Company in its sole discretion may decline to enter into Limited Firm Service Agreements or limit the days of availability and shall consider the Company's estimate of its distribution capacity and stored gas availability to provide Limited Firm Service

CURTAILMENT

If the Company's system operations require curtailment of firm service, service hereunder will be curtailed before all other firm service, and customer will be credited a portion of the Availability Charge based on the days of curtailed firm service and that contracted for

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

COST OF PROPANE GAS RATE

Availability Charge As specified in the Limited Firm Service Agreement between customer and Company D

Operational Cost per Therm	$0 13468	N
Cost of Propane Gas per Therm	$0 71415	N
Total Cost per Therm	$0 84883	N

DETERMINATION OF COST OF GAS

If the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference C C

DISTRIBUTION CHARGE N

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate N

(Continued on Sheet No 5-27)

SECTION 1 GENERAL SERVICE RULES

1.1 APPLICATION FOR SERVICE

A party desiring gas service must make application to the Company before commencing the use of the Company's service The Company reserves the right to require a signed application or written contract for service to be furnished All applications and contracts for service must be made in the legal name of the party desiring the service The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account Any person who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used

When required by governmental authority, a customer desiring new service or expanded service first must make application for and receive written approval from the Company

Subject to its rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service The customer will be responsible for payment of all service furnished through the date of discontinuance

1.2 SERVICE PROCESSING CHARGE

The Company will charge $15 00 for the initial establishment or the reestablishment of service for each customer If any combination of gas or electric services requested by a customer and furnished by the Company is established or reestablished at the same time and location, only one $15 00 charge will be made C C

If a customer requests reestablishment of service at a location where the same customer discontinued the same service within the preceding 12 month period, an additional reconnection fee will be assessed equal to the sum of the monthly minimum charges applicable during the period service was not taken N | N

1.3 ACCESS TO CUSTOMER'S PREMISES

Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incident to the service

1 4 CONTINUITY OF SERVICE

The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same

(Continued on Sheet No 6-4)

3.6 BILL DATE DUE

Bills are due and payable upon presentation For purposes of applying the late payment charge, the date due shown on the customer's bill shall be

Class	Date Due
Interruptible	Minimum of 10 working days after bill mailing date
All Other Classes	Next scheduled billing date minus four working days

3 7 ESTIMATED BILLS

An estimated bill will be rendered if it is impractical for the Company to read the meter or if customer fails to supply a meter reading form in time for the billing operation, or in cases of emergency An adjustment, if any, will be made in the bill based on the next meter reading

3.8 BILLING ADJUSTMENTS

In the event of a meter or billing error, as defined by the Public Service Commission's rules, the Company shall recalculate the bills for service during the period of the error and make adjustment of bills in accordance with the rules prescribed by the Commission If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10 00

3.9 RETURNED CHECK CHARGE

There shall be a charge of $25 00 for any check or draft submitted to the Company for payment that is dishonored or returned by the financial institution on which it is drawn T

3.10 ACCOUNT HISTORY CHARGE

There shall be a charge of $0 50 per account to the authorized requesting party for providing account history when such request involves 10 or more accounts, regardless of the type of account or number of meters An authorized requesting party may be the customer, a person authorized by the customer, or a person authorized by law to receive the requested information

5.2 MAIN EXTENSIONS

The Company will extend, enlarge, or change its gas mains or other facilities for supplying gas service when the anticipated revenue from the sale of additional service to result there from is such as to justify the expenditure When the expenditure is not so justified, the extension, enlargement, or change of facilities will be made only if the customer, at the Company's option

A Pays in advance to the Company in cash for the additional installation costs for excess footage as required by the Company's current footage costs or by promissory note acceptable to the Company, the portion of the capital expenditure not justified by the anticipated annual revenue with provision for refund of all or part of such payment, C

B Agrees to pay a special monthly charge,

C Agrees to pay annually a specified minimum charge, or

D Agrees to a combination of the above methods

In addition, a non-refundable payment in advance must be made covering the specified additional cost of any unusual construction

For each additional customer served directly from the main extension within five years from the date of its completion, the person who made advance payment will receive refunds based on the revenue to be received from the additional customers served from the extension and the costs required to serve such customers The total of such refunds will in no event exceed the total advance payment No refunds will be made for additional customers served by additional main extensions connected at any point to the first customer's original extension

For trailer parks, the Company will only extend its gas main to a delivery point at a permanent structure which houses facilities such as offices or laundry facilities It shall be the trailer park owner's responsibility to extend the distribution system to individual trailer sites D

(Continued on Sheet No 6-19)

5.3 WINTER CONSTRUCTION

When the service or main is installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30 or because the customer's property, or the streets leading thereto, are not ready to receive the service pipe or gas main by such date, such work will be subject to a winter construction charge when winter conditions of ground frost and/or snow exist, for the entire length of underground service or gas main installed Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install gas main or gas service pipe during the winter season The charges immediately below apply to frost depths of 18" or less At greater frost depths, the Company will individually determine the job cost The Company reserves the right to charge for any unusual winter construction expenses All winter construction charges are non-refundable and are in addition to any normal construction charges C

Winter Construction Charge		
Excavation		$400 per excavating unit
Main & Service Extensions	4 Inch or Under Pipe	$3 00 per foot
	Over 4 Inch Pipe	Determined Individually

C

5.4 LIMITATIONS ON THE AVAILABILITY OF GAS

New and existing customers requiring service for new or increased firm or interruptible gas loads must make an application for such service The Company shall apply the applicable limitations set forth in this section in determining whether to approve an application When supplies of gas and distribution capacity are adequate, Company will authorize connection of qualifying customers in the order that their application is received When an applicant is one for which a main extension is required, the application will be held until the main extension is approved, at which time it shall be processed the same as an on-main customer

A. New and Existing Firm Customers

1 New customers will be added in accordance with Section 5, EXTENSION RULES, of the General Rules and Regulations

2 Existing loads, except as noted below, may be increased and new loads added only with the approval of the Company based upon the adequacy of gas supplies and gas distribution capacity

3 Increases in existing loads for non-heating requirements not in excess of 0 5 Therm per hour do not require Company approval in accordance with Section 1 1, APPLICATION FOR SERVICE, of the General Rules and Regulations

(Continued on Sheet No 6-20)

5.5 SERVICE CONNECTIONS (Continued)

In addition, the Company will, at its own expense for all customers, furnish and install piping for a distance not to exceed five feet for

A Indoor Metering
From the service to the meter header or meter yoke

B Outdoor Metering
From the end of the horizontal service pipe to the outside of the customer's building wall

If this distance exceeds five feet in length, the Company will extend the piping if the customer will share the cost based on the Company's current footage costs C

5.6 TEMPORARY SERVICE D

The following special requirement is prescribed to govern temporary service

A customer taking temporary service (less than five years) will pay the rate applicable to the class of service rendered and will pay in advance the Company's specified cost, figured on a time and material basis, of the installation and removal of the facilities, including the meter required to furnish the desired service, less the salvage value of such facilities

Public Service Commission
Receipt of Payment

Receipt# 6270

Received 6/10/2005 Check# 111318 for $13,675 12

Docket # PU-04-578

Subject Utility Valuation

Prefile balance $3,200. Notify Mr. David Sparby

Mr. David Sparby
Northern States Power Company
414 Nicollet Mall
Minneapolis MN 55401

94 **PU-04-578** Pages 1

Receipt# 6,270 $13,675 12

by Northern States Power Company

06/10/2005

APPROVED
DATE: 6-8-05
KMF

MOTION

June 8, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No PU-04-578

I move the Commission bill Northern States Power Company for costs incurred to date in Case No. PU-04-578, Northern States Power Company, Natural Gas Rate Increase, Application

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A. Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

June 8, 2005

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

RE: Case No. PU-04-578
Northern States Power Company
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the June 8, 2005 Public Service Commission meeting for the expenses incurred to date in Case No. PU-04-578.

Under N.D.C.C. 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Admin Staff Officer
701-328-2401

Enc.

c: James P Johnson
Northern States Power Co
800 Nicollet Mall Ste 2900
Minneapolis MN 55401

Billing Statement

June 8, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

Expenses Incurred to Date:

Larkin & Associates	$200.87
Advertising Costs	299.97
TOTAL	$500.84

Amount Due:

Northern States Power Company $500.84

Send Payment and a Copy of this Statement To:

Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **2nd day of June, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of

Order Adopting Settlement

The envelopes were addressed as follows:

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747
Cert. No. 7003 2260 0001 3516 8958

Kent T Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3516 8965

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3516 8972

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Subscribed and sworn to before me
this **2nd day of June, 2005**

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **2nd day of June, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of.

Order Adopting Settlement

The envelopes were addressed as follows

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Subscribed and sworn to before me
this **2nd day of June, 2005**

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

frank.morehouse@gpng.com
Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

dhawk@simplot.com
David Hawk
J R Simplot
PO Box 27
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dickvoight@clearchannel.com

KFGO
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Fargo ND 58102-2966

mail@kvlytv11.com

KXJB-TV 4
4302 13th Ave S
Fargo ND 58103-3313

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Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
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P O Box 128
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Karen Collins
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State Capitol
Bismarck ND 58505

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dave.sederquist@xcelenergy.com
Dave Sederquist
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Fargo ND 58108-2747

Steven Tomac
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St Anthony ND 58566-9640

F James Moriarty
3 Litzsinger Ln
St Louis MO 63124-1416

Scott Geston
Cable One of Fargo
P O Box 10757
Fargo ND 58106-0757

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Patricia Estes
Daily News
PO Box 760
Wahpeton ND 58074-0760

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Jerry Tuchscherer
Grand Forks Board of Realtors
1407 24th Ave S #340
Grand Forks ND 58201-6761

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

News Director
KHND AM Radio
PO Box 6
Harvey ND 58341-0006

Kelley Richardson
King Publishing Co
PO Box 52210
Knoxville TN 37950-2210

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

Myer Shark
Knollwood Place Apts #221
3630 Phillips Pkwy
St Louis Park MN 55426

Minnesota PUC
121 E 7th Pl Ste 350
St Paul MN 55101-2147

Bruce Imsdahl
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Robert Burns
National Regulatory Research Inst
406 Bevis Hall 1080 Carmack
Columbus OH 43210

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

Jamie Seitz
Xcel Energy
825 Rice St
St Paul MN 55117

APPROVED
DATE: 6-1-05
KME

MOTION

June 1, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission adopt the Order Adopting Settlement in Northern States Power Company's Natural Gas Rate Increase application, Case No. PU-04-578.

PJF

91 PU-04-578 Pages 1
Motion
by Public Service Commission
06/01/2005 CC Comm Legal PUD (4) Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power company
Natural Gas Rate Increase
Application

Case No. PU-04-578

ORDER ADOPTING SETTLEMENT

June 1, 2005

Appearances

Commissioners: Tony Clark, Kevin Cramer, Susan E. Wefald.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission advocacy staff

James P. Johnson, Assistant General Counsel, Xcel Energy Services Inc , 800 Nicollet Mall, Suite 2900, Minneapolis, MN 55401, appearing for Northern States Power Company.

Allen C. Hoberg, Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, appearing as procedural Hearing Officer.

Preliminary Statement

On November 2, 2004, Northern States Power Company d/b/a Xcel Energy (Xcel) filed an application with the North Dakota Public Service Commission to increase its natural gas rates The requested increase in rates would generate additional natural gas revenues of $1,280,232 annually in North Dakota. Xcel's application is based on a 2004 projected test year

Xcel proposes to change natural gas rates for residential customers by increasing the Basic Service Charge per month from $5 50 to $8.50 and by decreasing the Distribution Charge per therm from $0.12480 to $0.12388 Xcel proposes to increase natural gas rates to small interruptible customers by increasing the Distribution Charge per therm from $0 07310 to $0.07740 Xcel proposes to increase natural gas rates to large interruptible customers by increasing the Distribution Charge per therm from $0 04390 to $0 04632 Xcel proposes to change natural gas rates to commercial and industrial service customers by changing the Basic Service Charge per month from $14 00 to $20.00 and changing the Distribution Charge per therm from $0 11280 to

$0 10120. Residential, commercial, and industrial customers will be able to determine whether their bill will change by reviewing their gas usage throughout the year.

Xcel anticipates that an average residential customer bill will increase by $2 to $3 per month Xcel further proposes a rate element for residential customers in order to capture what natural gas customers would have paid toward recovery of distribution costs had weather-normalized use not deviated from the sales volume established in the rate proceeding Xcel's proposed rate changes would not affect the cost of purchased gas, which is separately recovered through the Cost of Gas billing provision

On November 18, 2004 the Commission issued an order suspending Xcel's general rate increase application

Concurrent with the general rate increase application, Xcel submitted a request for interim rate relief, based on a 2004 projected test year, to generate additional annual revenues of $741,000. To accomplish this, Xcel filed an Interim Rate Adjustment of 5.84% to be applied to the non-gas portion of the bill (the customer charge plus the distribution charge).

On December 1, 2004 the Commission ordered the interim rates effective for service rendered on or after January 1, 2005

On December 15, 2004 the Commission issued a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline. The technical hearing was scheduled for April 20, 2005, and Public Input Sessions via interactive video teleconference were scheduled for February 7, 2005 in Bismarck, Fargo, and Grand Forks Any person wishing to intervene as a party in the proceeding was to file a petition for intervention by January 31, 2005. No one petitioned to intervene as a party in the proceeding.

Issues to be considered in this matter include:

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

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

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

4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

5 Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6 Other relevant information or proposals concerning the proceeding

On February 17, 2005 Xcel and Staff filed a Settlement Agreement. Xcel and Staff agreed to two rate alternatives

Option A.

1. A final increase in rates to yield increased annual revenues of $886,697 effective for service rendered on or after June 1, 2005.
2. A $598,955 increase in total residential test year revenues, a $225,532 increase to commercial firm service revenues, and a $57,142 increase to commercial interruptible service revenues
3. An increase in the residential monthly Basic Service Charge to $8.75, an increase in the commercial firm service monthly Basic Service Charge to $20, a decrease in the volumetric residential class Distribution Charge to $0 10 per therm, a decrease in the volumetric commercial firm class Distribution Charge to $0.10710 per therm, an increase in the volumetric small interruptible class Distribution Charge to $0.0774 per therm and an increase in the volumetric large interruptible class Distribution Charge to $0 04632 per therm.
4 Deferring consideration of Xcel's proposed Partial Decoupling Rider to a future application

Option B·

1 A final increase in rates to yield increased annual revenues of $745,000 effective for service rendered on or after June 1, 2005
2. A $457,902 final increase in total residential test year revenues, a $225,532 final increase to commercial firm service revenues, and a $57,142 final increase to commercial interruptible service revenues
3. Replace the existing residential monthly Basic Service Charge and the residential volumetric Distribution Charge with a flat monthly Delivery Services Charge of $15.69. Rates for commercial firm and interruptible service would be the same as provided in Option A.
4. Withdraw Xcel's proposed Partial Decoupling Rider.

Additional terms of the Settlement Agreement common to both Option A and Option B include·

1. For purposes of determining the overall revenue requirement, a test year average rate base amount of $42,398,000.

2 A $15 per check charge for checks returned due to non-sufficient funds.

3 Modifications to winter construction charges

4 Revised disconnection/reconnection charges and tariffs

On March 9, 2005 the Commission issued a Notice of Informal Hearing and Notice of Cancellation of Formal Hearing stating that, instead of a formal hearing, an informal hearing would be held on April 20, 2005 for an overview of the Settlement Agreement and giving interested persons an opportunity to be heard. The hearing was held as scheduled.

On April 8, 2005 Xcel filed a revision to its existing disconnection/reconnection charges and tariffs

Having considered this matter, the Commission finds Option B of the Settlement Agreement filed February 17, 2005 is reasonable and should be approved Therefore, the Commission issues the following:

Order

1 The Settlement Agreement, Option B filed February 17, 2005, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

2 Xcel's interim increase in annual revenues of approximately $741,000 will remain effective until the revised tariff sheets contemplated by this order take effect, at which time the interim rates will expire and be replaced by the rates reflected in the compliance tariffs Since the final rates exceed the interim rates, no refunds will be due

3 Xcel shall file compliance tariffs to implement final rates, as agreed to in the Settlement Agreement and at the Informal Hearing, to yield a final annual revenue increase of not more than $745,000

PUBLIC SERVICE COMMISSION

"NAY"		
Susan E. Wefald	**Tony Clark**	**Kevin Cramer**
Commissioner	**President**	**Commissioner**

Settlement Agreement.pdf

RECEIVED
FEB 17 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company /d/b/a Xcel Energy Natural Gas Rates

Case No. PU-400-04-578

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 17th day of February, 2005, by and between the North Dakota Public Service Commission Staff ("Staff") and Northern States Power Company d/b/a Xcel Energy, a Minnesota corporation ("Xcel Energy" or "the Company"), (collectively, the "Parties"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in just and reasonable rates for the Company's retail natural gas operations in North Dakota.

PROCEDURAL HISTORY

1. On November 2, 2004, Xcel Energy filed a Notice of Change in Rates for Natural Gas Service with the North Dakota Public Service Commission ("Commission"), based on a 2004 test year, to become effective January 1, 2005. The Notice proposed an increase in natural gas retail and miscellaneous revenues of $1,280,000, or about 1.8 percent overall. Xcel Energy proposed to increase residential bills approximately 4.6 percent through a $3.00 increase in the monthly Basic Service Charge coupled with a slight reduction in the volumetric Distribution charge The Company proposed to increase Commercial - Interruptible service revenues by 0.5 percent. Other tariff changes included increases in Returned Check charges and a refinement of winter construction charges. The Company also proposed a "Partial Decoupling Rider" designed to recover volumetrically charged distribution revenues lost to the ongoing trend of declining use per customer. Filed with the Notice were revised tariffs, exhibits, and supporting statements.
2. Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase was for $741,000 or 1.1

percent overall, to be effective January 1, 2005 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C 49-05-06.

3. On December 2, 2004, Xcel Energy filed direct testimony in support of its Notice of Change in Natural Gas Rates.

4 On November 18, 2004, the Commission issued an order suspending Xcel Energy's general rate increase application and set the matter for investigation and hearing.

5. On November 23, 2004, Commission advisory staff filed comments stating that Xcel Energy's interim rate petition complied with N.D.C.C 49-05-06. On December 1, 2004, the Commission issued an order allowing interim rates as proposed by the Company to be placed into effect January 1, 2005, subject to refund.

6. On December 15, 2004, the Commission issued a Notice of Hearing, Notice of Public Input Session, and Notice of Intervention Deadline ("Commission Notice") which set forth the following issues to be considered in this case:

- What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
- What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
- Other relevant information or proposals concerning the proceeding.

7. On February 7, 2005, the Commission conducted a public input session as provided in the Commission Notice. The session utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, and Bismarck.

8. Under the Commission Notice the deadline for filing a Petition to Intervene was January 31, 2005 No party filed such a petition in this proceeding

9. Discovery requests were served on Xcel Energy by the advocacy Staff and were responded to by the Company.

10 Various settlement discussions were held between the Company and the Commission advocacy staff during December 2004, January 2005, and February 2005. As a result of those discussions, the Parties reached this Settlement Agreement.

11. The administrative record supports the Settlement Agreement. Accordingly, the Parties jointly recommend the Commission issue an Order approving this Settlement Agreement, including either of the two options contained therein, without conditions or modifications

TERMS OF SETTLEMENT AGREEMENT

I. RATE OPTIONS

The Parties agree to rate Options A and B discussed below and summarized on Schedules A, B, and C attached to this Settlement. The parties recommend the Commission select and approve the rate option of the Commission's choice:

Option A: Traditional Two-Part Residential Delivery Service Rates

1 **Revenue Increase**.

The Parties agree to, and recommend the Commission approve, a net increase in Xcel Energy's natural gas rates for retail customers in North Dakota to yield an annual retail sales and miscellaneous revenue increase of approximately $887,000, or 1 2%, effective for service rendered on or after June 1, 2005. The Company shall file compliance tariff pages setting forth the revised gas rates and tariffs provided by this Settlement Agreement rate option at least 30 days prior to the effective date.

2 **Revenue Apportionment**.

The Parties agree to, and recommend the Commission approve, an overall increase in total residential test year revenues of approximately 2.3 percent, a 0.7 percent increase to commercial firm service revenues, and a 0.5 percent overall increase in commercial interruptible service revenues, as shown on Schedule A.

3 **Rate Design**

The Parties agree to, and recommend the Commission approve, increasing the residential and commercial firm service monthly Basic Service Charge and decreasing the corresponding volumetric class Distribution Charge as specified on Schedule C The Parties also agree to, and recommend the Commission approve, increases to the commercial interruptible service Distribution Charges, also shown on Schedule C

4. **Partial Decoupling Rider (Declining Use Per Customer Recovery)**

The Parties agree to defer consideration of the Company's proposed Partial Decoupling Rider (the declining residential use per customer recovery mechanism) to a future rate application

Option B: Single Fixed Residential Delivery Services Rate

1 **Revenue Increase**.

The Parties agree to, and recommend the Commission approve, a net increase in Xcel Energy's natural gas rates for retail customers in North Dakota to yield an annual retail sales and miscellaneous revenue increase of approximately $745,000, or 1 1%, effective for service rendered on or after June 1, 2005. The Company shall file compliance tariff pages setting forth the revised gas rates and tariffs provided by this Settlement Agreement rate option at least 30 days prior to the effective date

This reflects an overall retail revenue increase approximately equal to the level currently being recovered by the company in interim rates plus an

estimated $3,400 of increased returned check charges This lower overall revenue increase (compared to Option A) is acceptable to the Company because declining use per customer trends would no longer adversely impact residential revenues previously collected through volumetric charges.

2. **Revenue Apportionment**.

The Parties agree to an overall increase in total residential test year revenues of approximately 1 7 percent All other customer classes would experience revenue increases equal to that agreed to under Option B (and summarized on Schedule B).

3 **Rate Design**

The Parties agree to, and recommend the Commission approve, replace the existing residential monthly Basic Service Charge and the residential volumetric Distribution Charge with a flat monthly Delivery Services Charge of $15.69, as shown on Schedule C Rates for commercial Firm and Interruptible service would be the same as provided in rate Option A.

4 **Partial Decoupling Rider (Declining Use Per Customer Recovery)**

The parties agree that the Partial Decoupling Rider proposed in the Application would be unnecessary under Option B because residential delivery revenues would be, by definition, decoupled from customer usage.

II. TERMS COMMON TO EITHER RATE OPTION

1 **Rate Base**

For purposes of determining the overall revenue requirement, the Parties agree to a test year average rate base amount of $42,398,000

2 **NSF Check Charges**

The Parties agree to, and recommend the Commission approve, a $15 per check charge for checks returned due to non-sufficient funds ("NSF") This is the same amount as the currently effective NSF charge levied by the

Company to electric customers under its North Dakota Electric Rate Book tariffs

3 **Winter Construction Charges**

The Parties agree to, and recommend the Commission approve, the modifications to winter construction charges as identified on Schedule 3, page 29 (Tariff Section 6, Sheet 19) of the rate Application

4. **Disconnect/Reconnect Charges**

The Parties agree that Xcel Energy may need to revise its natural gas tariffs to discourage customers from "gaming" the existing natural gas rate structure to avoid payment of fixed monthly charges (either the residential Basic Service Charge under Rate Option A or the residential Delivery Services Charge under Rate Option B). This "gaming" occurs primarily when customers regularly request Xcel Energy to disconnect their natural gas service prior to warm weather months and then place a reconnection order prior to the next heating season Such "gaming" both reduces the Company's recovery of fixed distribution costs and increases operating costs for disconnection and reconnection. The Company's current natural gas tariffs do not contemplate and adequately recover the costs of these types of service requests The Parties agree that the Company shall submit, by April 1, 2005, a miscellaneous tariff filing to establish disconnection/reconnection charges and tariffs similar to those currently in effect for natural gas customers of Montana-Dakota Utilities.

5 **Interim Rates**

The parties agree the final rates effective June 1, 2005 under both rate Options A and B of this Settlement Agreement will generate increased revenues equal to or exceeding the increase collected by the Company under the interim rates implemented January 1, 2005 The parties agree the interim rates will remain in effect for all customer classes for the period January 1, 2005 to May 31, 2005, and no interim rate refunds will be issued

III. OTHER TERMS AND CONDITIONS

1. **Basis of Settlement** It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission The Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

2 **Effect of the Settlement Negotiations** It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or otherwise

3. **Applicability and Scope** This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding

4 **Effective Date** This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in Section I of Terms of Settlement Agreement

5 **Modification** If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if any party files a letter with the Commission with three (3) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party

Dated this 15th day of February 2005.

Northern States Power Company d/b/a Xcel Energy

By: _____

Vice President, Northern States Power

Dated this 17th day of February, 2005.

Northern Dakota Public Service Commission Staff

By. _____

Chief Counsel

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Revenue Apportionment (Case No. PU-400-04-578)

Option A - Traditional Two-Part Residential Delivery Rate

Customer	Previous Revenues	Interim Revenues	Interim Increase	%	Settlement Revenues	Increase over Previous	%	Increase over Interim	%
Residential	$26,361,011	$26,718,808	$357,797	1 4%	$26,959,966	$598,955	2 3%	$241,158	0 9%
Commercial	$30,884,941	$31,197,667	$312,726	1 0%	$31,110,473	$225,532	0 7%	-$87,194	-0 3%
Total Firm	$57,245,953	$57,916,475	$670,522	1 2%	$58,070,439	$824,486	1 4%	$153,964	0 3%
Sm Comm	$3,912,461	$3,944,778	$32,317	0 8%	$3,938,974	$26,513	0.7%	-$5,804	-0 1%
Lg Indust	$7,682,678	$7,719,432	$36,754	0 5%	$7,713,308	$30,630	0.4%	-$6,124	-0 1%
Total Interruptible	$11,595,140	$11,664,210	$69,070	0.6%	$11,652,282	$57,142	0.5%	-$11,928	-0 1%
Total Retail	$68,841,092	$69,580,685	$739,593	1.1%	$69,722,721	$881,629	1.3%	$142,036	0 2%
Misc. Tariffs	$2,765,694	$2,767,101	$1,407	0.1%	$2,770,762	$5,068	0.2%	$3,661	0 1%
Grand Total	$71,606,786	$72,347,786	$741,000	1.0%	$72,493,483	$886,697	1.2%	$145,697	0 2%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Revenue Apportionment (Case No. PU-400-04-578)

Option B - Single Fixed Residential Delivery Rate

Customer	Previous Revenues	Interim Revenues	Interim Increase	%	Settlement Revenues	Increase over Previous	%	Increase over Interim	%
Residential	$26,361,011	$26,718,808	$357,797	1 4%	$26,818,913	$457,902	1.7%	$100,105	0 4%
Commercial	$30,884,941	$31,197,667	$312,726	1 0%	$31,110,473	$225,532	0.7%	-$87,194	-0 3%
Total Firm	$57,245,953	$57,916,475	$670,522	1 2%	$57,929,386	$683,433	1.2%	$12,911	0 0%
Sm Comm	$3,912,461	$3,944,778	$32,317	0 8%	$3,938,974	$26,513	0.7%	-$5,804	-0 1%
Lg Indust	$7,682,678	$7,719,432	$36,754	0 5%	$7,713,308	$30,630	0.4%	-$6,124	-0 1%
Total Interruptible	$11,595,140	$11,664,210	$69,070	0 6%	$11,652,282	$57,142	0.5%	-$11,928	-0 1%
Total Retail	$68,841,092	$69,580,685	$739,593	1 1%	$69,581,668	$740,576	1.1%	$983	0.0%
Misc Tariffs	$2,765,694	$2,767,101	$1,407	0 1%	$2,770,492	$4,798	0 2%	$3,391	0 1%
Grand Total	$71,606,786	$72,347,786	$741,000	1 0%	$72,352,160	$745,374	1 0%	$4,374	0 0%

Schedule C

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Rate Summary (Case No PU-400-04-578)

	Previous Rates	Interim Rates	Settlement Agreement Option A Residential Two-Part Rate	Settlement Agreement Option B Residential Single Fixed Rate
Residential				
Basic Service Charge (per month)	$5 50	$5 83	$8.75	
Distribution Charge (per therm)	$0 12480	$0 13212	$0 10000	
Delivery Services (per month)				$15 68
Commercial Firm				
Basic Service Charge (per month)	$14.00	$14 83	$20 00	$20.00
Distribution Charge (per therm)	$0 11280	$0.11942	$0.10710	$0.10710
Small Interruptible				
Basic Service Charge (per month)	$75.00	$79 39	$75.00	$75.00
Distribution Charge (per therm)	$0.07310	$0 07740	$0 07740	$0 07740
Large Interruptible				
Basic Service Charge (per month)	$275.00	$291.07	$275 00	$275 00
Distribution Charge (per therm)	$0.04390	$0 04647	$0 04632	$0 04632

CONCURRING OPINION
Commissioner Tony Clark

June 1, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No PU-04-578

Advocacy staff and Xcel Energy have proposed two settlement options for the commission to consider in this case. In deciphering whether option A or B is best for consumers, option B wins in a landslide Average residential rates will be lower under option B than under option A. The new billing format will decrease the price volatility in winter gas bills. It ends unfair rate discrimination against customers living in older homes. And it helps lower the chance that we will hear another rate case in the near future.

Xcel appears entitled under the law to an increase of some amount Even advocacy staff acknowledges such by virtue of the proposed settlement that is before us. Under the settlement the commission is approving, the increase will only be about $1 a month averaged over the course of a year for a typical Xcel customer. While no one likes even a small rate increase, it should be noted that regulated rates have been exceptionally stable for Xcel. Over the past 20 years, there will have now been two rate decreases and two rate increases that essentially net each other out. (I only wish the unregulated cost of gas was as stable For this, federal policy makers should be ashamed for their lack of attention But I digress)

The most noticeable change being implemented is that billing formats have been substantially improved in a way that most customers will appreciate It is an accepted ratemaking principle that fixed, non-usage sensitive costs should be recovered through fixed charges and variable, usage sensitive costs should be recovered through variable charges Unfortunately, regulators and utilities across the country have too often drifted from sound economics in favor of less than straightforward ways of implementing utility rates A common trick for hiding rate increases is to incorporate the increase into volumetric (usage-based) charges. I applaud this commission, its staff and Xcel for providing an option that does not fall into this trap It is, however, easy to see why some regulators and utilities find such schemes so appealing. Volumetric charges are hard to understand. They are calculated in fractions of cents and are based on usage, so it is difficult for consumers to ever know when and how their rate has increased. It is a perfect solution for those wanting to deflect and obscure the attention of the general public

But political expediency for regulators and utilities carries a heavy price for consumers Moving these fixed costs into variable charges does not mean that consumers pay any less In actuality, they pay just as much over the course of time as

they would if sound decisions were implemented. (Under Option A, they would pay more.) Instead, when fixed costs are recovered through usage, consumers have the burden of paying for most of the costs of the distribution network when they can least afford it, in the middle of winter This is especially painful for consumers in a northern state like ours Residential gas usage is relatively stable in sunbelt states, therefore recovering distribution costs via the volume of gas used may not be so offensive, because the costs will naturally be spread throughout the year. Indeed, irrational usage-based charges might even be somewhat tolerable where usage is somewhat consistent throughout the year Electricity usage, for example, is becoming much less seasonable for most utilities But in North Dakota, we know all too well that natural gas usage surges during our coldest months This means that any usage based gas charge, such as proposed in settlement option A, will be paid for disproportionately when usage is the highest, and when the unregulated cost of the gas is also highest When gas distribution costs are nearly all fixed regardless of usage, I cannot fathom why consumers should be asked to pay more during cold weather as opposed to warm. The option the commission is selecting will be preferred by a majority of consumers, by far Helping to mitigate the extreme price volatility of winter gas bills will be welcomed by consumers. While the total monthly bill will be only a few dollars higher for most consumers during the warmest months, it is estimated to reduce an average January bill by over $25. (It should be noted that the cost of gas itself will still be a usage based charge, which is entirely appropriate for obvious reasons. For this reason, consumers' bills will still be more expensive when gas usage is the highest, and consumers will still have the incentive to conserve energy)

Placing fixed costs in usage-based charges can also add a significant burden to those living in older homes – often our senior citizens and those on fixed incomes I formerly represented north Fargo in the legislature That portion of the city is a prime example of why inappropriately applied usage charges can discriminate against these customers. Legislative District 44 is one of the most established residential districts in the state. The residences within it are overwhelmingly single family homes, and most of them have been there for some time Older homes tend to be less well insulated than newer homes They typically also have furnaces which cannot compare to the super-high efficiency furnaces now standard in most newly constructed homes The distribution costs associated with these homes are no more than of any other home on the network. (In fact, a strong case can be made that they cost less due to a variety of factors) Yet irrationally recovering fixed, non-usage sensitive costs through usage-based charges, such as under option A, requires these customers to shoulder an unfair portion of the cost of the distribution network. Option B ends such unjustifiable subsidies and discrimination

Finally, by selecting option B, the commission is, hopefully, reducing the chance that we will be holding another rate case soon. Cost recovery via usage creates utility company revenue streams that fluctuate based on the technological efficiency of the equipment using the natural gas, as well as seasonal weather fluctuations Such uncertainty benefits neither consumers nor the utility, because there is a negligible ability for any single party to control them Because the utility company has more

certainty as to what its revenue stream will be, efficient planning that benefits both consumers and the utility is enhanced

Tony Clark, President

DISSENTING OPINION
Commissioner Susan E. Wefald

June 1, 2005

Northern States Power Company **Case No. PU-04-578**
Natural Gas Rate Increase
Application

I am voting no on this rate case decision because I do not agree Option B is the best alternative to chose in this matter I am not against giving Xcel Energy a rate increase. However, the Settlement Agreement filed by Staff and Xcel offered the Commission a choice of two rate alternatives

Option B places all costs that relate to the customer distribution system for residential customers in the basic monthly service charge This means that even if customers do not use any gas in a particular month, they will still have a fee of $15.69 to receive gas service. Commissioners Clark and Cramer's decision will make us the first Commission in the country to adopt this type of "one part" tariff.

Option A, which I prefer, places a portion of the customer costs in a basic monthly service charge ($8 75) and places a portion of the customer costs on each unit of gas used by the customer (10 cents per therm) This "two part" tariff is the method which has been used in the past by this Commission

I prefer Option A for the following reasons:

Costs for distribution services are typically divided between those costs which are fixed per person, and those costs which relate to the amount of commodity used In fact, when customer charges were first started, all costs were first established as "usage" (per therm) charges.

However, a one part tariff "did not capture the non linear relationship between costs and the amount of services " [1] Commissions then started to use a two part tariff which consisted of a fixed component and a usage component The fixed component included costs for meters, reading meters, billing, collecting and accounting and these were put into a "customer charge." Many times this component did not include distribution main (pipeline) costs because these are installed to serve volumetric needs of the customers and thus should be established as usage charges.

In this case, my fellow commissioners are deciding that both fixed costs and usage costs should be placed into one customer charge I do not agree that we should be moving again to a one part tariff Two part tariffs better capture the relationship between the types of costs and the types of activities that cause those costs

[1] Mohammad Harunuzzaman and Sridarshan Koundinya, Cost Allocation and Rate Design for Unbundled Gas Services, (The National Regulatory Research Institute, 2000) 94

Although, Option A gives an increase to Xcel of $886,697 and Option B gives Xcel an increase of $745,000, many customers would pay less per year for their natural gas services under Option A than Option B All customers who use 828 or less therms of gas a year will pay more under Option B One half of Xcel residential customers (17,277) in North Dakota use 828 therms or less a year.

I am also curious about why only residential customers were singled out for this "one part tariff" If this is good for residential customers, why isn't it good for commercial and interruptible customers as well?

Also, I do not agree with notices and announcements in this case which talk about an "overall" increase An "overall" increase interprets the rate increase in relationship to the total bill of the gas customer. However, gas commodity charges have been decoupled from the distribution charges on the bill, and this case is about distribution charges.

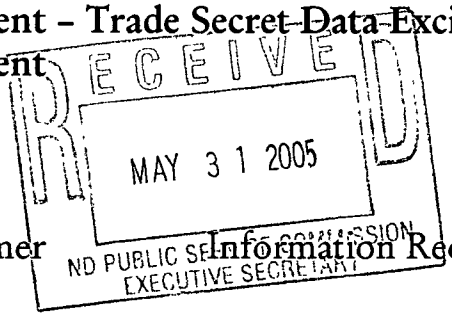
An "overall" increase percentage can change depending on the price the customer is paying in any month for natural gas. Now that gas prices for Xcel customers are around $8.00 a dekatherm, the "overall" percentage increase granted to the company becomes very small

The reality is that the Commission is granting a 4.7% increase to Xcel for distribution charges in this rate case Residential customers will be seeing a distribution charge increase of 7 6%, commercial customers 4.2%, small interruptible customers 4.9% and large Interruptible Customers 2 8%.

Susan E. Wefald

Susan E Wefald, Commissioner

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☒ Public Document



Xcel Energy
Docket No.: PU-400-04-578
Response To: Comm. Kevin Cramer Information Request 4-03
Date Received: 5/25/05

Question:

Please provide sample residential bills for the months of August and January, in bill format, showing what the bill will look like before and after Option B rates are implemented

Response:

Attached are examples of Xcel Energy residential natural gas bill for the months of January and August. Each bill illustration was created based on the average residential usage for January and August during the 2004 calendar year.

Page 1 shows the January bill under current rates; page 2 shows the January bill under Option B rates; page 3 shows the August bill under current rates; and page 4 shows the August bill under Option B rates. Other information on the bill is for illustrative purposes only.

Response By: Dave Sederquist
Title: Sr. Regulatory/Financial Consultant

Department: North Dakota Jurisdiction
Telephone: 701-241-8632
Date: 5/27/05

Xcel Energy™

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Date Due	Pay	Amount Enclosed
02/18/05	$191 12	
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Fax 1-800-311-0050

Northern States Power Co
PO BOX 8
Eau Claire, WI 54702-0008

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Billing Summary		
Residential		
Previous Balance 1/05	$147 00	
Payment Received As Of 1/17	$147 00	CR
Balance As Of 2/06	$0 00	
Current Energy Charges 2/06	$191.12	
Total	**$191.12**	

Averages for Billing Period

	This Year	Last Year
Average Temperature	11	8
Gas therms per day	6 0	6 7
Cost per Day	$5 25	$5 40

Current Charges

Gas Charges Usage Period: 1/02/05 to 2/02/05

Pressure Correction Adjustment 186 ccf x 1 100 = 205 ccf
Heat Content Adjustment 205 ccf x 1 0123 = 207 therms
Invoice # 13829815

Service 31 days		
Basic Service Charge		$5 50
Distribution Charge	207 therms @ $0 12480	$25 85
Cost of Gas	207 therms @ $0 72697	$150.57
Subtotal		**$181.92**
City Fees	@ 2.00%	$3 64
City Tax	@ 1 00%	$1 86
State Tax	@ 2 00%	$3.71
Total Amount		**$191.12**

Meter Reading Information

Meter # 0000956037	
Reading on 2/02	2542
Reading on 1/02	2356
Total 31 Days (ccf)	186

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Statement Date 2/06/05

See back of bill for more information

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Date Due	Pay	Amount Enclosed
02/18/05	$174 67 Thank You	

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Billing Summary

Residential		
Previous Balance 1/05	$140 98	
Payment Received As Of 1/17	$140 98	CR
Balance As Of 2/06	$0 00	
Current Energy Charges 2/06	$174.67	
Total	**$174.67**	

Averages for Billing Period

	This Year	Last Year
Average Temperature	11	8
Gas therms per day	6.0	6 7
Cost per Day	$4.84	$4 70

Current Charges

Gas Charges Usage Period: 1/02/05 to 2/02/05
Pressure Correction Adjustment 186 ccf x 1 100 = 205 ccf
Heat Content Adjustment 205 ccf x 1 0123 = 207 therms
Invoice # 13829815
Service 31 days

Meter Reading Information
Meter # 0000956037
Reading on 2/02 2542
Reading on 1/02 2356
Total 31 Days (ccf) 186

Delivery Services			$15 69
Cost of Gas	207 Therms @	$0 726970	$150.57
Subtotal			**$166.26**
City Fees	@ 2 00%		$3 33
City Tax	@ 1 00%		$1 70
State Tax	@ 2 00%		$3.39
Total Amount			**$174.67**

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Date Due	Pay	Amount Enclosed
09/18/05	$20 73	
	Thank You	

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Northern States Power Co
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Eau Claire, WI 54702-0008

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Billing Summary

Residential		
Previous Balance 8/05	$14 88	
Payment Received As Of 8/17	$14.88	CR
Balance As Of 9/06	$0.00	
Current Energy Charges 9/06	$20.73	
Total	**$20.73**	

Averages for Billing Period

	This Year	Last Year
Average Temperature	81	83
Gas therms per day	0 5	0 5
Cost per Day	$0 54	$0 55

Current Charges

Gas Charges Usage Period: 1/02/05 to 2/02/05
Pressure Correction Adjustment 15 ccf x 1.100 = 17 ccf
Heat Content Adjustment 17 ccf x 1 0123 = 17 therms
Invoice # 13829815
Service 31 days

Basic Service Charge		$5 50
Distribution Charge	17 therms @ $0.12480	$2 08
Cost of Gas	17 therms @ $0.64103	$12.14
Subtotal		**$19.73**
City Fees	@ 2.00%	$0.39
City Tax	@ 1.00%	$0 20
State Tax	@ 2.00%	$0.40
Total Amount		**$20.73**

Meter Reading Information
Meter # 0000956037

Reading on 2/02:	2371
Reading on 8/02:	2356
Total 31 Days (ccf)	15

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Statement Date 9/06/05

See back of bill for more information.

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Date Due	Pay	Amount Enclosed
09/18/05	$29 24 Thank You	

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Fax 1-800-311-0050 Eau Claire, WI 54702-0008

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Billing Summary

Residential		
Previous Balance 8/05	$23.56	
Payment Received As Of 8/17	$23.56	CR
Balance As Of 9/06	$0.00	
Current Energy Charges 9/06	$29.24	
Total	**$29.24**	

Averages for Billing Period

	This Year	Last Year
Average Temperature	81	83
Gas therms per day	0.5	0 5
Cost per Day	$0 81	$0 80

Current Charges

Gas Charges Usage Period: 1/02/05 to 2/02/05
Pressure Correction Adjustment 15 ccf x 1 100 = 17 ccf
Heat Content Adjustment 17 ccf x 1 0123 = 17 therms
Invoice # 13829815
Service 31 days

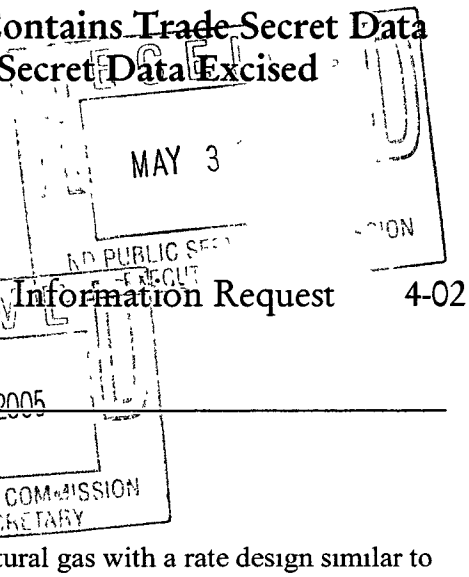
Meter Reading Information
Meter # 0000956037
Reading on 2/02 2371
Reading on 8/02 2356
Total 31 Days (ccf) 15

Delivery Services			$15.69
Cost of Gas	17 Therms @	$0 64103	$12.14
Subtotal			**$27.83**
City Fees	@ 2 00%		$0.56
City Tax	@ 1 00%		$0 28
State Tax	@ 2.00%		$0.57
Total Amount			**$29.24**

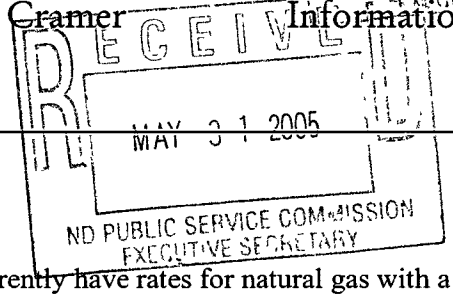
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Xcel Energy
Docket No.: PU-400-04-578
Response To: Comm. Kevin Cramer Information Request 4-02
Date Received: 5/25/05



Question:

Please provide a list of companies that currently have rates for natural gas with a rate design similar to option B in this proceeding.

Response:

At this point in time, we are aware of a single application (Atlanta Gas Light) of a 100% fixed rate for natural gas distribution services. Other gas utilities, while generally recognizing that higher fixed monthly residential rates represent the most efficient method of reducing intra-class subsidies and bill volatility, have settled for other mechanisms or approaches to achieving similar bill normalization impacts.

As shown in a 2003 listing from the American Gas Association (Schedule 1), at least 24 utilities have implemented various forms of normalization mechanisms that, generally speaking, create bill adjustments to offset the impacts of abnormal gas usage on monthly delivery charge revenues. In fact, the North Dakota Public Service Commission recently approved a billing adjustment calculation, known as the Distribution Delivery Stabilization Mechanism ("DDSM") for Montana-Dakota Utilities to eliminate from customer bills any excess or deficient non-gas charges due to abnormal weather. Mechanisms like this can be costly to implement because of the billing system and accounting process modifications that are typically required (Xcel Energy estimated that it would have cost $300,000 to $500,000 to program a DDSM-type mechanism into its new CRS billing system). In addition, these mechanisms can lead to more complex customer bills, usually require significant company and regulatory resources to maintain and monitor, and at best can only approximate "normal" charges.

In his prefiled direct testimony, Nick Paluck included as Schedule 5 descriptions of a sampling of the various approaches that have been take by the natural gas local distribution company (LDC) industry to deal with the pricing issues created by traditional natural gas rate structures that employ a volumetric charge to recover largely fixed delivery costs. Included in the summary are examples representative of the industry trend toward – at a minimum – higher monthly customer charges. (In the Company's case, referred to as the Basic Service Charge.)

Some utilities have implemented fixed gas bill offerings similar to the *WorryProof Bill* program sponsored by Alliant Energy which locks in a guaranteed annual gas charge (including a program fee) for participating customers. Customers pay the same amount each month for the entire year, and there are no true-up adjustments to contend with. Although program fees add to the customer's gas cost, there is value for many customers in having predictability and uniform bills.

Cynthia Marple, Director of Rates and Regulatory Services at the American Gas Association, states that while AGA has not formally compiled information demonstrating the trend toward higher fixed monthly fees, there is little doubt that the industry is moving in this direction. This is in recognition that using volumetric rates to recover non-gas delivery costs unnecessarily inflates winter heating bills, creates intra-class subsidies, and contributes to customer bill volatility in a period of relatively high and fluctuating wholesale natural gas prices.

In this rate case and Settlement Agreement, the Company believes the North Dakota Public Service Commission has an opportunity to adopt a rate structure that will accomplish what other Commissions and gas utilities have been trying to accomplish through more complex and resource-intensive methods.

Response By: Dave Sederquist
Title: Sr. Regulatory/Financial Consultant
Department: North Dakota Jurisdiction
Telephone: 701-241-8632
Date: 5/27/05

Questions of the Quarter: 1 Does your company utilize any of the following practices that have the effect of normalizing consumption or revenue? (Y or N)

Company	Area	Weather Normalization Adjustment Clause	Revenue Normalization Adjustment Provision	Deferred Accounting Order	Cost Tracker	PGA Flow-Through	Mandated Annual Filings	Frequent Proactive Rate Case	Incentive or PBR
Aquila Networks	CO								
Aquila Networks	IA	Y	Y	Y	N	Y	Y	N	N
Aquila Networks	KS								
Aquila Networks	MI								
Aquila Networks	MN - NMU	Y	Y	N	N	Y	Y	N	N
Aquila Networks	MN - PNG-GLGT	Y	Y	N	N	Y	Y	N	N
Aquila Networks	MN - PNG-NNG	Y	Y	N	N	Y	Y	N	N
Aquila Networks	MN - PNG-VGT								
Aquila Networks	MO - Eastern	Y	Y	Y	Y	Y	Y	N	N
Aquila Networks	MO - Northern	Y	Y	Y	Y	Y	Y	N	N
Aquila Networks	MO - Southern	Y	Y	Y	Y	Y	Y	N	N
Aquila Networks	MO (SJLP)	Y	Y	Y	Y	Y	Y	N	N
Aquila Networks	NE - Lincoln								
Aquila Networks	NE - Metro								
Aquila Networks	NE - Outstate								
Arkansas Western Gas	AR	Y	N	N	N	Y	N	N	N
Atmos Energy	KY	Y	N	N	N	Y	N	N	Y
Atmos Energy Corp	GA	Y	N	N	N	Y	N	N	Y
Atmos Energy Corp	IA	N	N	N	N	Y	N	N	N
Atmos Energy Corp	IL	N	N	N	N	Y	N	N	N
Atmos Energy Corp	MO	N	N	N	N	Y	N	N	N
Atmos Energy Corp	TN	Y	N	N	N	Y	N	N	Y
Atmos Energy Corp	VA	N	N	N	N	Y	Y	N	N
Atmos Energy Corporation	CO	N	N	N	N	N	N	N	N
Atmos Energy Corporation	KS	Y	N	N	N	N	N	N	N
Avista Utilities	CA					Y			
Avista Utilities	ID					Y			
Avista Utilities	OR			Y		Y			
Avista Utilities	WA					Y			
Baltimore Gas & Electric Co	MD	X							
Bay State Gas	MA	NO	NO	NO	YES	YES	NO	NO	NO
CenterPoint Energy Minnegasco	MN	N	N	N	Y (CIP)	Y	Y(Not rate case)	N	N
Central Hudson	NY	N	N	Y	N	Y	N	N	N
Citizens Gas & Coke	IN	No	No	No	No	No	No	No	No
City Public Service	TX San Antonio	N	N	N	N	N	N	N	N
Columbia Gas of Kentucky, Inc	KY	Y	Y	Y	N	Y	N	N	N
Columbia Gas of Maryland, Inc	MD	Y	Y	Y	Y	Y	Y	N	N
Columbia Gas of Ohio, Inc	OH	N	Y	Y	Y	Y	Y	N	N
Columbia Gas of Pennsylvania, Inc	PA	N	Y	Y	Y	Y	Y	N	N
Columbia Gas of Virginia, Inc	VA	N	Y	Y	N	Y	N	N	N
Con Edison	NY	Yes				Yes		3 year settlement	

Questions of the Quarter: 1 Does your company utilize any of the following practices that have the effect of normalizing consumption or revenue? (Y or N)

Company	Area	Weather Normalization Adjustment Clause	Revenue Normalization Adjustment Provision	Deferred Accounting Order	Cost Tracker	PGA Flow-Through	Mandated Annual Filings	Frequent Proactive Rate Case	Incentive or PBR
Conectiv	DE	Y							
Connecticut Natural Gas Corp	CT					Y			Y
Consumers Energy	MI					y			
Delta Natural Gas Company Inc	KY	Y				Y			
Dominion East Ohio	OH	N	N	Y	Y	Y	Y	N	
Dominion Hope	WV	N	N	N	N	Y	Y - PGA	Optional	N
Dominion Peoples	PA	N	N	N	N	Y	Y	N	N
Energy West Inc	MT								
ENSTAR Natural Gas Co	AK Southcentral	N	N	N	N	Y	N	N	N
Equitable Gas	PA	No							
Fort Pierce Utilities Authority	FL					Y			
Gaz Metro	QC	Y	N	Y	N	Y	Y	Y	Y
Indiana Gas	IN	N	N	N	N	N	N	N	N
KeySpan Energy Del -LI	NY Long Island	Y	Y	Y		Y	Y		
KeySpan Energy Del -NY	NY NYC	Y	Y	Y		Y	Y		
Keyspan Energy Delivery - NE	MA (Boston Gas)	N	N	N	N	N	N	N	Y
Keyspan Energy Delivery - NE	MA (Colonial Gas-Cape)	N	N	N	N	N	N	N	N
Keyspan Energy Delivery - NE	MA (Colonial Gas-Lowell)	N	N	N	N	N	N	N	N
Keyspan Energy Delivery - NE	MA (Essex Gas)	N	N	N	N	N	N	N	N
Keyspan Energy Delivery - NE	NH (EnergyNorth)	N	N	N	N	N	N	N	N
Kokomo Gas & Fuel	IN	N	N	N	N	N	N	N	N
Laclede Gas	MO	N-see comment 2	N	N	N	Y	N	N	N-see comment 3
Louisville Gas and Electric Co	KY	X				X			X
Madison Gas & Electric Co	WI	N	N	N	N	N	N	N	N
Memphis Light, Gas, and Water	TN Shelby County								
Metropolitan Utilities	NE	N	N	N	N	Y	N	N	N
Michigan Consolidated Gas Co	MI	N	N	N	N	N	N	N	N
Missouri Gas Energy	MO	N	N	Y	N	Y	N	N	N
Montana-Dakota Utilities Co	MT	N	N	N	N	Y			
Montana-Dakota Utilities Co.	ND	Y	N	N	N	Y			
Montana-Dakota Utilities Co	SD	N	N	N	N	Y			
Montana-Dakota Utilities Co	WY	N	N	N	N	Y			
Mountaineer Gas	WV	No	Yes	Yes	Yes	Yes	Yes	No	No
National Fuel Gas	NY	Y	N	N	N	N	N	N	N
National Fuel Gas	PA	N	N	N	N	N	N	N	N
New England Gas	MA Fall River	N	N	N	N	N	N	N	N
New England Gas Co	RI	Y	N	N	N	N	N	N	N
New Jersey Natural Gas Co	NJ	Y	N	N	N	N	Y	N	N
Niagara Mohawk Power Corp a Nat	NY	Y	Y	Y	N	Y	Y	N	Y
NICOR	IL	N	N	N	N	Y	N	N	N
North Shore Gas	IL	N	N	N	N	N	N	N	N

Questions of the Quarter: 1 Does your company utilize any of the following practices that have the effect of normalizing consumption or revenue? (Y or N)

Company	Area	Weather Normalization Adjustment Clause	Revenue Normalization Adjustment Provision	Deferred Accounting Order	Cost Tracker	PGA Flow-Through	Mandated Annual Filings	Frequent Proactive Rate Case	Incentive or PBR
Northern Indiana Fuel & Light	IN	N	N	N	N	N	N	n	N
Northern Indiana Public Service Co	IN	N	N	N	N	N	N	N	N
Northern Utilities	ME	N	N	N	Y	Y	N	N	N
Northern Utilities	NH	N	N	N	Y	Y	N	N	N
NSTAR Gas Company	MA	N	N	N	N	Y	Y(Gas Cost Adj)	N	N
NUI Elizabethtown Gas	NJ	Y			Y	Y	Y		
NYSEG	NY Binghamton	Y	Y						
NYSEG	NY Combined	Y	Y						
Ohio Valley Gas Corp	IN ANR	Yes	No	On Variance	Yes	No - Qtrly	No	No	No
Ohio Valley Gas Corp	IN TX Gas	Yes	No	On Variance	Yes	No - Qtrly	No	No	No
Ohio Valley Gas, Inc	IN	Yes	No	On Variance	Yes	No - Qtrly	No	No	No
Oklahoma Natural Gas	OK	y	?	y	?	y	y	n	n
Orange & Rockland Utilities	NY	Yes	No	Yes	No	Yes	Yes	No(3 Year	No
Pacific Gas and Electric Company	CA								
PECO an Exelon Company	PA								
Peoples Gas	IL	N	N	N	N	N	N	N	N
Philadelphia Gas Works	PA	Y	N	N	N	N	Y	N	N
PSE&G	NJ								
Public Service Company	CO								
Public Svc Co of NM	NM	N	N	Y	N	Y	N	N	N
Puget Sound Energy	WA								
Questar Gas Company	UT	Yes				Yes			
Questar Gas Company	WY	Yes				Yes			
Richmond Utilities	KY	N	N	N	N	Y	Y	N	N
Rochester Gas & Electric Corporati	NY	n	n	n	n	n	n	n	n
SIGECO	IN	N	N	N	N	N	N	N	N
So. Jersey Gas Co.	NJ	Y							
Southern CT Gas Co	Connecticut								
Southwest Gas	AZ								
Southwest Gas	CA								
Southwest Gas	NV								
Southwestern Va Gas	VA	N	N	N	N	N	Y	N	N
Superior Water, Lt & Power Co	WI	N	N	N	N	Y	N	N	Y
Texas Gas Service	TX Austin	Y	N	N	N	N	N	N	N
Texas Gas Service	TX El Paso	N	N	N	N	N	N	N	N
The Cincinnati Gas & Electric Co	OH					X			
The Union Light, Heat and Power C	KY					X			
TXU Corp.	TX, Dallas	Y	N	N	Y	Y	Y	N	N
UGI Utilities, Inc	PA								
Union Gas Limited	ON Southwestern								
VEDO	OH	N	N	N	N	N	N	N	N

Questions of the Quarter: 1 Does your company utilize any of the following practices that have the effect of normalizing consumption or revenue? (Y or N)

Company	Area	Weather Normalization Adjustment Clause	Revenue Normalization Adjustment Provision	Deferred Accounting Order	Cost Tracker	PGA Flow-Through	Mandated Annual Filings	Frequent Proactive Rate Case	Incentive or PBR
Vermont Gas Systems, Inc	VT	N	N	Y	N	N	N		N
Washington Gas	DC	N	N	N	Y	Y	Y	N	N
Washington Gas	MD	N	N	N	Y	Y	Y	N	N
Washington Gas	VA	N	N	N	Y	Y	Y	N	N
Wisconsin Gas Company	WI					X			X
Wisconsin Power and Light Co	WI	Y	Y			Y		Y	Y
Wisconsin Public Service Corporati	MI	N	N	N	N	Y	Y	N	N
Wisconsin Public Service Corporati	WI	N	N	N	N	Y	Y	Y	N
Xcel Energy	MN	NO	NO	Yes	Yes	yes	yes	no	no
Yankee Gas	MA								

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RECEIVED
MAY 31 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Xcel Energy
Docket No.: PU-400-04-578
Response To: Commissioner S. E. Information Request 4-01
Date Received: 5/25/05

Question:

What is the number of residential customers in North Dakota who use 828 therms or less per year?

Response:

While the Company is unable to perform a query on our current customer database by Tuesday, May 31st to determine the specific number of North Dakota customers who use less than 828 therms of natural gas over the past year, other data can be used to approximate this number.

A similar type of analysis performed using 2003 data from retail gas customers within our various Minnesota service areas confirmed that roughly half of all residential customers use less than 828 therms (an amount very close to the residential average). In addition, other information in the study also provides information about the relationship between average annual use per customer and family income that is relevant to this response.

Schedule 1, page 1, shows the segmentation of actual average annual gas usage for all residential customers in Minnesota who were on our system for a full year in 2003. It is evident from the cumulative customer column that about 52% of residential customers used 1,000 therms or less of natural gas that year. In 2003 average use per Minnesota residential customer was about 15% higher than in North Dakota. Given that, we can estimate that approximately 52% of residential customers in North Dakota used less than 850 therms. Taking it a step further, one can logically assume that the percentage of residential customers using less than 828 therms per year would be quite close to 50% (about 17,250 customers).

As it relates to the Company's present gas rates and the proposed rates in the Settlement Agreement before the Commission, the residential customers using less than 828 therms/year currently receive a rate subsidy because they pay less than their cost of service, with part of the subsidy paid by Residential customers who average more than 828 therms of consumption per year (a portion of the subsidy is paid by the customers in other customer classes where rates are set above cost in order to minimize the rate increase to residential customers). Rate Option A in the Settlement Agreement partially reduces the level of subsidy by moving more of the fixed cost recovery to the Basic Service Charge Option B eliminates the intra-class subsidy altogether, so that all residential customers pay the same share of the distribution, metering, and billing costs for delivering the natural gas to their homes.

This data also indicates that lower income customers (here defined as those receiving LIHEAP funding) do not appear to be lower users of natural gas than other residential customers on the Company's system. The graph on Schedule 1, page 2 shows that the distribution of annual usage among low-income

Response to Commissioner Wefald request for information
by Northern States Power Company by
05/31/2005 CC Comm Legal PUD (4) Mike

customers is the same as that of the entire residential class In other words, the use of a volumetric Distribution charge to recover some fixed delivery services costs does not provide any energy bill relief to low income customers. In fact, the data indicates an equal likelihood that low-income customers living in older, less efficient homes may be subsidizing natural gas delivery services for high-income customers living in newer, more energy-efficient homes.

It should also be noted that in North Dakota, the vast majority of apartment dwellers are not equipped with individual gas meters, and as such would not be affected by the residential rate design options contemplated in the Settlement Agreement which is before the Commission Generally, apartment buildings heated by natural gas have a single meter, and apartment owners pay a small commercial firm gas rate, which is then allocated to tenants either through their rent or as a separate utility charge

Again, Rate Option A in the Settlement Agreement partially reduces the level of subsidy within the residential class by moving more of the fixed cost recovery to the Basic Service Charge. Option B would eliminate any intra-class subsidy by recovering all fixed costs through the monthly Basic Service Charge.

Response By: Dave Sederquist
Title: Sr. Regulatory/Financial Consultant
Department: North Dakota Jurisdiction
Telephone: 701-241-8632
Date: 5/27/05

Northern States Power Co. d/b/a Xcel Energy

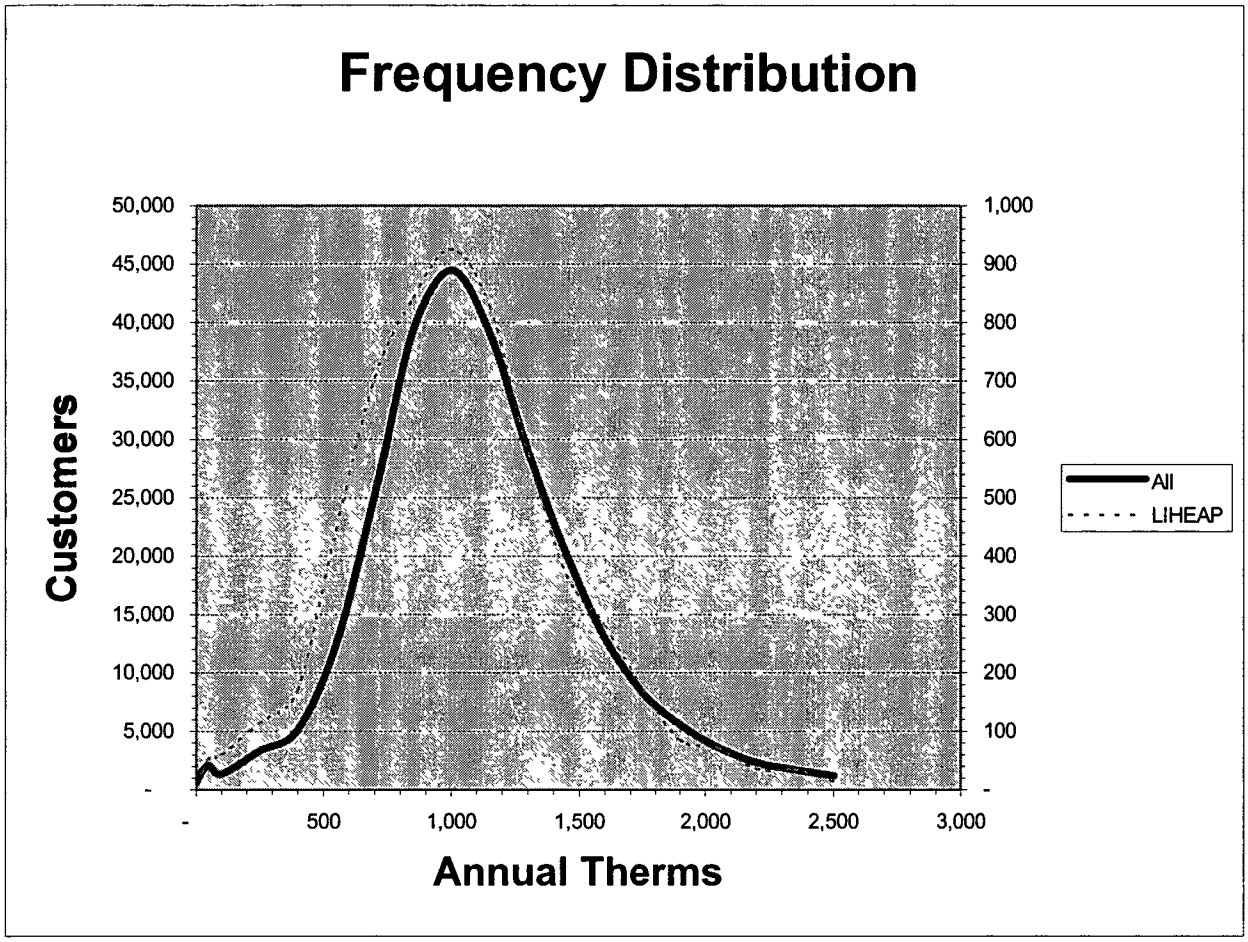
All Customers

(a)	(b)	(c)	(d)
Interval	Annual Therms	Interval Count	Cumulative Count
1	-	667	667
2	25	1,666	2,333
3	50	2,086	4,419
4	100	1,344	5,763
5	250	3,309	9,072
6	400	5,115	14,187
7	550	12,406	26,593
8	700	25,294	51,887
9	850	39,307	91,194
10	1,000	44,493	135,687
11	1,150	39,112	174,799
12	1,300	28,997	203,796
13	1,450	20,138	223,934
14	1,600	12,965	236,899
15	1,750	8,262	245,161
16	1,900	5,557	250,718
17	2,050	3,613	254,331
18	2,200	2,338	256,669
19	2,350	1,693	258,362
20	2,500	1,198	259,560
21	3,500	2,814	262,374
22	5,000	715	263,089
23	10,000	188	263,277
24	12,000	11	263,288
25	15,000	6	263,294

LIHEAP Customers

(a)	(b)	(c)	(d)
Interval	Annual Therms	Interval Count	Cumulative Count
1	-	7	
2	25	31	31
3	50	53	84
4	100	60	144
5	250	114	258
6	400	171	429
7	550	445	874
8	700	706	1,580
9	850	842	2,422
10	1,000	926	3,348
11	1,150	828	4,176
12	1,300	575	4,751
13	1,450	367	5,118
14	1,600	280	5,398
15	1,750	170	5,568
16	1,900	85	5,653
17	2,050	72	5,725
18	2,200	36	5,761
19	2,350	34	5,795
20	2,500	14	5,809
21	3,500	35	5,844
22	5,000	2	5,846
23	10,000	-	5,846
24	12,000	-	5,846
25	15,000	-	5,846

Graph 1


Frequency Distribution
Customers
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
1,000
900
800
700
600
500
400
300
200
100
-
-
500
1,000
1,500
2,000
2,500
3,000
Annual Therms
All
LIHEAP

Scott, Sandi L.

From: Fahn, Patrick J
Sent: Thursday, May 26, 2005 8 37 AM
To: Xcel - Dave Sederquist
Cc: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Subject: NSP gas rate case information request from Commissioner Cramer

Commissioner Cramer would like Xcel to file the following in Case No. PU-04-578

A list of companies that currently have rates for natural gas with a rate design similar to Option B in this proceeding.

Sample residential bills for the months of August (1.2 dk) and January (17.5 dk), in bill format, showing what the bill will look like before and after Option B rates are implemented.

Due to the holiday right before the meeting at which this case is to be decided, the sooner you can provide this information, the better If you have a problem providing it relatively quickly, please let me or Annette.

Both this request and the response will be docketed

Thank you

Patrick J Fahn
Chief Engineer, Public Utilities Division
600 East Boulevard
Bismarck ND 58505-0480
701-328-4077
701-328-2410 (fax)

pfahn@state nd us

Scott, Sandi L.

From: Jeffcoat-Sacco, Illona
Sent: Wednesday, May 25, 2005 4 46 PM
To: Binek, William W , Diller, Michael R ; Lein, Jerry R ; Sederquist, Dave
Cc: Fahn, Patrick J , Bendish, Annette M , -Grp-PSC Commissioners, Scott, Sandi L
Subject: NSP gas rate case information request from Commissioner Wefald

Commissioner Wefald would like the following information from staff or the company:

Number of residential customers in ND who use 828 therms or less per year.

Due to the approaching holiday right before the meeting at which this case is to be decided, the sooner you can provide this information, the better. If you have a problem providing it relatively quickly, please let me, Pat or Annette know.

Both this request and the response will be docketed.

Thank you.

Illona A. Jeffcoat-Sacco
Executive Secretary
Director, Public Utilities Division
Public Service Commission
600 E. Boulevard Ave , Dept 408
Bismarck, ND 58505-0480
701-328-2407 (fax· 701-328-2410)
ijs@state nd us

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by Grand Forks Herald, Inc
05/12/2005 C Comm Legal PUD (4) Mike ALJ

Associated Press

MAI ULLE, Mo. – Jeffery Lotsha ossed regularly He brushed faithfully, sometimes four or five times in a day.

All that care makes his condition seem incomprehensible – at the age of just 33, Lotshaw's grin is toothless. His teeth all broke apart, tarnished with yellow and black.

"Before I started doing meth, I didn't have a cavity in my head," said Lotshaw, imprisoned on drug charges at Missouri's Maryville Treatment Center.

The growing use of highly addictive methamphetamine throughout the country is creating a prominent scar on an increasing number of users – rotting, brittle teeth that seem to crumble from their mouths.

Methamphetamine can be made with a horrid mix of substances, including over-the-counter cold medicine, fertilizer, battery acid and hydrogen peroxide.

Together, the chemicals reduce a user's saliva, which neutralizes acids and physically clears food from the teeth, said Dr. Eric Curtis, an Arizona-based spokesman for the Academy of General Dentistry.

"When the saliva isn't flowing, the bacteria build up a lot faster," said Dr. Darrell Morton, an Atlanta dentist.

Meth users also may neglect their teeth, or moisten their dry mouths with high-sugar drinks, and anxiety caused by the drug prompts th o grind their teeth, which sp decay.

The problem is particularly noticeable among inmates, whose oral problems have some prison systems struggling to provide dental care.

"They're rotting teeth, missing teeth, rotting way into the gums," said Kathy Bachmeier, the head of medical services for North Dakota's prisons. "It's ugly."

There are no statistics on "meth mouth" – as the condition has come to be known – because addicts are sometimes reluctant to admit their drug use and because it is difficult to distinguish between damage done by bad dental hygiene and that caused by narcotics. But there are signs it is on the rise around the country.

The head of the company in charge of dental care for Missouri inmates says he is seeing teeth rotted by meth use nearly every day. In North Dakota, the number of days a dentist was serving inmates jumped from 50 in 2000 to 78 in 2004. And the tab for inmates' dental care in Minnesota rose from $1 2 million five years ago to about $2 million last year

"There are more and more urgent care needs, which pushes back routine care like cleanings," said Nanette Schroeder, director of health services for Minnesota's Corrections Department. "They're seeing just worse mouths, generally."



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Dr. Terry Dwe
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ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Natural Gas Rates
Your Opportunity To Be Heard

The North Dakota Public Service Commission invites you to a PUBLIC INPUT SESSION on the application of NSP (d/b/a Xcel Energy) to increase natural gas rates.

WHEN: February 7, 2005 at 7:00 pm (CST)

WHERE:

Fargo	North Dakota State University E. Morrow Lebedeff, Room 183
Grand Forks	University of North Dakota Gamble Hall, Room 120
Bismarck	Veterans Memorial Public Library 515 North 5th Street, Lower Level

The public will also be able to hear the input session by connecting to the Commission's web site at www.psc.state.nd.us then clicking on the "Broadcast of Public Input Sessions" link. The Commission will receive e-mail questions during the input session at ndpsc@state.nd.us

Mail comments to the Public Service Commission, 600 East Boulevard Avenue, Dept. 408, Bismarck ND 58505-0480. Individuals requiring special accommodations contact Illona A. Jeffcoat-Sacco (1-701-328-2400 or TTY 1-800-366-6888) *at least one working day prior* to the meeting

Xcel Energy™

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave.sederquist@xcelenergy com

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MAY - 3 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

April 24, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

SUBJECT: Questions during the April 20, 2005 Informal Hearing
(Case No. PU-400-04-578)

Dear Illona·

At the April 20, 2005 Informal Hearing, questions were raised about a couple of issues that representatives from Northern States Power Company d/b/a Xcel Energy were unable to reconcile during the hearing. This letter responds specifically to those questions.

1. **Average Natural Gas Use per Customer**

Commissioner Wefald inquired about the average natural gas use per North Dakota residential customer (88.1 Dekatherms) as depicted in the declining use chart on page 6 of Schedule 7 in the application, and the average use (72.8 therms) as shown on Slide 6 during the March 8th informal hearing and Schedule 4 (71.1 therms) of the supplementary Settlement Agreement document provided just prior to the March 8th hearing.

The average usage of 88.1 on the chart in the application reflected *dekatherms per year* in the 2004 test year. 88.1 dekatherms is equivalent to 881 therms. Dividing 881 by 12 results in a monthly average of 73.4 therms, which is consistent with the 72.8 therm monthly average contained in the test year.[1]

The monthly average of 71.1 therms as indicated on the supplementary Schedule 4 was calculated using *actual* gas sales data for 2004, so it too will differ slightly from the 2004 test year projection, which was calculated assuming normal weather and "typical" heating degree days.

2. **Sub-Totals on a Revised Class Cost of Service Schedule**

At the March 8th informal hearing, Commissioner Wefald inquired about possibility of making modifications to the Company's filed Class Cost of Service Study ("CCOSS") so that it would clearly indicate the allocation to rate component of various costs and

[1] The combination of actual and forecasted sales and customer data used to calculate the 88 1 dekatherm per year (or 73 4 therms per month) average use differed slightly from that used in the actual case test year This resulted in the insignificant difference between 73 4 therms and 72 8 therms

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investment assigned to the Residential class. In addition, Commissioner Wefald requested that the Company provide a working version of the CCOSS so that Advisory Staff could model different assumptions.

It is a substantial effort to modify the CCOSS, a complicated Excel spreadsheet model. In an attempt to respond in a timely manner, a Company analyst worked several days and evenings inserting additional columns into the model to show the more detailed breakdown of Residential costs. He divided the costs included in the Residential column into two subcategories: "Res Cust" and "Res Other". However, in order to expedite submission of the information to the Advisory Staff, he did not take the additional time necessary to create formulas that would total the information in the two subcategories, believing the CCOSS subtotals were being provided to show the relative allocation, not a complete and detailed analysis of the Residential costs. The modified CCOSS model was originally labeled "For Settlement Discussion purposes only – Confidential" (later this was removed at the request of Advisory Staff) and was sent to Advisory Staff on March 24th. Having received no further inquiry or direction from Commission staff for the next month, Xcel Energy assumed the Commission and Advisory Staff were satisfied with the information provided.

While the Company believes it provided accurate line item information that showed the breakdown of the costs in the two subcategories, it was apparent in last week's hearing that Commissioner Wefald expected the CCOSS subcategory results to "tie out" just as the original CCOSS filed with the Application did. A corrected CCOSS is attached herewith, with corrected sub-totals in the newly inserted columns of data.

The Company regrets any confusion or inconvenience that resulted from these two topics at the April 20th informal hearing. We remain committed to providing information and answering questions in a timely and thorough manner, as we have done throughout this case.

Don't hesitate to call me if you have any questions.

Sincerely,

David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Co. d/b/a Xcel Energy

Summary Functionalized Rate Base

	Plant In Service	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Production	P10		0	1,660	0	741	1,660	741	919	0	0
2	Storage	P20		0	3,396	0	1,516	3,396	1,516	1,880	0	0
3	Transmission	P30		0	3,142	0	1,232	3,142	1,232	1,529	71	309
4	Distribution	P40		50,446	9,785	37,219	3,838	60,231	41,057	17,243	751	1,180
5	Sub-total	P60		50,446	17,983	37,219	7,327	68,429	44,547	21,571	822	1,489
6	General	P70		1,235	440	804	287	1,675	1,090	528	20	36
7	Common	P80		3,638	1,297	2,368	844	4,935	3,213	1,556	59	107
8	TBT Investment	PTBT		2	0	1	0	2	1	1	0	0
9	**Total**	PLANT		**55,320**	**19,721**	**40,393**	**8,458**	**75,041**	**48,851**	**23,656**	**901**	**1,633**
	Depreciation Reserve											
10	Production	A10		0	1,213	0	542	1,213	542	671	0	0
11	Storage	A20		0	2,439	0	1,089	2,439	1,089	1,350	0	0
12	Transmission	A30		0	1,721	0	675	1,721	675	838	39	169
13	Distribution	A40		19,971	3,774	13,723	2,625	23,745	16,348	6,657	287	453
14	Sub-total	A60		19,971	9,147	13,723	4,930	29,118	18,654	9,516	326	623
15	General	A70		665	304	426	195	969	621	317	11	21
16	Common	A80		1,780	815	1,140	522	2,595	1,662	848	29	55
17	**Total**	DEPR		**22,416**	**10,266**	**15,289**	**5,648**	**32,682**	**20,937**	**10,681**	**366**	**699**
18	**Net Plant With TBT**	NGPIS		32,905	9,454	25,103	2,811	42,359	27,914	12,975	536	934
	Accumulated Deferred Taxes	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
19	Production	DT10		0	28	0	12	28	12	16	0	0
20	Storage	DT20		0	155	0	69	155	69	86	0	0
21	Transmission	DT30		0	241	0	95	241	95	117	5	24
22	Distribution	DT40		4,334	841	2,948	579	5,175	3,528	1,482	65	101
23	Sub-total	DT60		4,334	1,265	2,948	755	5,599	3,704	1,700	70	125
24	General	DT70		147	43	97	28	190	126	58	2	4
25	Common	DT80		382	111	252	74	493	326	150	6	11
26	Non-Plant related	DT90		-260	-79	-179	-54	-339	-233	-89	-8	-9
27	**Total**	ADT		4,603	1,340	3,120	803	5,943	3,922	1,819	70	131
	Construction Work in Progress	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
28	Production	CP10		0	38	0	17	38	17	21	0	0
29	Storage	CP20		0	52	0	23	52	23	29	0	0
30	Transmission	CP31		0	11	0	4	11	4	5	0	1
31	Distribution	CP42		0	0	0	0	0	0	0	0	0
32	Sub-total	CP60		0	101	0	44	101	44	55	0	1
33	General	CP54		0	0	0	0	0	0	0	0	0
34	Common	CP64		0	0	0	0	0	0	0	0	0
35	Non-Plant related	CP90		0	0	0	0	0	0	0	0	0
36	**Total**	CWIP		0	101	0	44	101	44	55	0	1
	Net Investment Rate Base	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
37	Production	NIRB10		0	457	0	204	457	204	253	0	0
38	Storage	NIRB20		0	854	0	381	854	381	473	0	0
39	Transmission	NIRB30		0	1,191	0	467	1,191	467	580	27	117
40	Distribution	NIRB40		26,141	5,170	20,548	634	31,311	21,181	9,105	399	625
41	Sub-total	NIRB60		26,141	7,672	20,548	1,686	33,813	22,234	10,410	426	742
42	General	NIRB70		423	93	281	63	516	344	154	7	11
43	Common	NIRB80		1,477	370	976	248	1,847	1,224	558	24	41
44	TBT Investment			2	0	1	0	2	1	1	0	0
45	Non-Plant related	NIRB90		260	79	179	54	339	233	89	8	9
46	**Total**	NIRB		28,302	8,215	21,984	2,053	36,517	24,036	11,211	466	804
	Additions											
47	Materials & Supplies	MSP		150	38	99 9	25 6	188	125 5	56	2	4
48	Gas in Storage	MSG		0	3,834	0	1,182	3,834	1,182	1,488	242	922
49	Non Plant Asset & Liabilities	NON		-440	-134	-302	-92	-574	-394	-152	-13	-15
50	Prepaids and Other	MISC		325	2,657	155	1,107	2,982	1,262	1,449	95	177
51	Cash Working Capital	WCASH		-54	-495	-35	-171	-549	-206	-221	-27	-95
52	**Total**			**-20**	**5,901**	**-82**	**2,052**	**5,881**	**1,970**	**2,620**	**299**	**993**
53	**Rate Base**	**BASE**		**28,282**	**14,116**	**21,902**	**4,104**	**42,398**	**26,006**	**13,831**	**764**	**1,797**

Summary Income Statement

		Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	**Operating Revenues**									
2	Retail	8,262	60,579	3,197	23,440	68,841	26,637	31,114	3,845	7,245
3	Other Operating	47	2,719	40	1,165	2,766	1,205	1,395	73	93
4	**Total Operating Revenues**	**8,309**	**63,298**	**3,236**	**24,606**	**71,607**	**27,842**	**32,509**	**3,918**	**7,338**
5	**Expenses**									
6	Operating Expenses									
7	Purchased Gas (PGA)	0	55,825	0	20,478	55,825	20,478	25,658	3,272	6,417
8	Purchased Gas other	0	1,442	0	644	1,442	644	798	0	0
9	Production	0	724	0	258	724	258	323	30	113
10	Transmission	0	96	0	38	96	38	47	2	9
11	Distribution	1,427	237	1,043	126	1,664	1,169	445	19	31
12	Customer Accounting	1,200	0	1,015	0	1,200	1,015	180	3	1
13	Customer Service and Information	22	0	19	0	22	19	3	0	0
14	Administrative and General	866	592	592	349	1,458	941	429	37	51
15	Amortizations	3	17	1	7	20	8	9	1	2
16	Sales, Econ Develop & Other	0	131	0	57	131	57	10	53	11
17	**Total O&Ms**	**3,517**	**59,065**	**2,671**	**21,956**	**62,582**	**24,627**	**27,903**	**3,417**	**6,635**
18	Depreciation Expense	2,044	654	1,354	391	2,698	1,745	857	35	61
19	Taxes other than Income Taxes	839	327	571	187	1,165	758	368	15	25
20	Deffrred incomes Taxes and ITC	384	167	260	86	551	347	182	6	16
21	Gross Earnings	0	979	0	403	979	403	446	62	67
22	Op Income before taxes	1,524	2,107	(1,620)	1,582	3,632	(38)	2,753	382	534
23	State and Federal Income Taxes	-126	534	(1,200)	529	408	(671)	773	134	172
24	**Total Expense**	**6,658**	**61,725**	**3,656**	**23,553**	**68,383**	**27,209**	**30,528**	**3,670**	**6,976**
25	AFUDC	0	0	0	0	-	-	-	-	-
26	**Total Operating Income**	**1,651**	**1,573**	**(419)**	**1,053**	**3,224**	**633**	**1,980**	**248**	**362**
27	**Rate Base**	**28,282**	**14,116**	**21,902**	**4,104**	**42,398**	**26,006**	**13,831**	**764**	**1,797**
28	**Return on Rate Base**	**5 837%**	**11 143%**	**-1 915%**	**25 646%**	**7 603%**	**2 435%**	**14 319%**	**32 427%**	**20 158%**
29	**Return on Equity at present rates**	**4 349%**	**14 911%**	**-1 339%**	**-1 083%**	**7 865%**	**-2 423%**	**21 232%**	**57 275%**	**32 854%**
30	**Required Rate of Return on Rate Base**	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**
31	**Required Operating Income**	**2,667**	**1,331**	**2,065**	**387**	**3,998**	**2,452**	**1,304**	**72**	**169**
32	**Income Deficiency**	**1,016**	**-242**	**2,485**	**-666**	**774**	**1,819**	**-676**	**-176**	**-193**
33	**Revenue Deficiency**	**1,681**	**-400**	**4,110**	**-1,101**	**1,280**	**3,009**	**-1,119**	**-291**	**-319**
34	**Percent increase indicated**	**20 23%**	**-0 63%**	**127 0%**	**-4 47%**	**1 8%**	**10 8%**	**-3 4%**	**-7 4%**	**-4 3%**

Equal Rate of Return

	Total Retail Rev Reqt	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Return On Rate Base			9 43%	9 43%	9 43%	9 43%	9 43%	9 43%	9 43%	9 43%	9 43%
2	Equalized Retail Revenue			9,990	60,132	4,223	25,423	70,122	29,646	29,995	3,554	6,926
3	Present Retail Revenue			8,262	60,579	3,197	23,440	68,841	26,637	31,114	3,845	7,245
4	Revenue Deficiency			1,728	(447)	1,027	1,982	1,281	3,009	-1,119	-291	-319
5	Deficiency / Pres Rev			20 92%	-0 74%	32 12%	8 46%	1 86%	11 30%	-3 60%	-7 56%	-4 40%
	Internal Rev Reqt											
6	Customer Rev Reqt			9,943	0	7,460	0	9,943	7,460	2 350	94	38
7	Ave Monthly Customers			40,827	0	34,553	0	40,827	34,553	6,141	110	23
8	Rev Reqt $ / Mo / Cust			20 29	0	17 99	0 00	20 29	17 99	31 89	71 30	138 47
9	Capacity Rev Reqt			0	3,212	0	1,331	3,212	1,331	1,652	43	186
10	Annual MCF Sales			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
11	Rev Reqt $ / MCF (MCF per Month)			0	0 33	0 00	0 44	0 33	0 44	0 43	0 07	0 08
	Capacity - Sub Classification											
12	Capacity -Base Rev Reqt			0	715	0	225	715	225	283	43	164
13	Annual MCF Sales			0	9,788,919	3,018,662	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
14	Rev Reqt $ / MCF			0 00	0 07	0 00	0 07	0 07	0 07	0 07	0 07	0 07
15	Capacity -Seasonal Rev Reqt			0	1,213	0	533	1,213	533	658	0	22
16	Annual MCF Sales			0	9,788,919	3,018,662	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
17	Rev Reqt $ / MCF			0	0 12	0 00	0 18	0 12	0 18	0 17	0 00	0 01
					0							
18	Peak Shaving Rev Reqt			0	1,285	0	573	1,285	573	711	0	0
19	Ave Monthly Customers/ (Design Day)			0	9,788,919	3,018,662	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
20	Rev Reqt $ / MCF			0	0 13	0 00	0 19	0 13	0 19	0 19	0 00	0 00
21	Energy Rev Reqt			0	1,142	0	377	1,142	377	336	145	284
22	Annual MCF Sales			0	9,788,919	3,018,662	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
23	Rev Reqt $ / MCF			0	0 12	0 00	0 12	0 12	0 12	0 09	0 24	0 12
24	Total Internal Rev Reqt			9,943	4,354	7,460	1,708	14,297	9,168	4,337	282	509
25	Rev Reqt $ / MCF			1 02	0 44	2 47	0 57	1 46	3 04	1 14	0 46	0 22
	External Rev Reqt											
26	Capacity Rev Reqt			0	8,695	0	3,871	8,695	3,871	4,824	0	0
27	Rev Reqt $ / MCF			0 00	0 89	0 00	1 28	0 89	1 28	1 27	0 00	0 00
28	Energy Rev Reqt			0	47,130	0	16,607	47,130	16,607	20,834	3,272	6,417
29	Rev Reqt $ / MCF			0 00	4 81	0 00	5 50	4 81	5 50	5 48	5 31	2 73
30	Total External Rev Reqt			0	55,825	0	20,478	55,825	20,478	25,658	3,272	6,417
31	Rev Reqt $ / MCF			0 00	5 70	0 00	6 78	5 70	6 78	6 75	5 31	2 73
	Total Rev Reqt											
32	Cust Rev Reqt $ / MCF			1 02	0 00	2 47	0 00	1 02	2 47	0 62	0 15	0 02
33	Demd Rev Reqt $ / MCF			0 00	1 22	0 00	1 72	1 22	1 72	1 70	0 07	0 08
34	Ener Rev Reqt $ / MCF			0 00	4 93	0 00	5 63	4 93	5 63	5 57	5 54	2 85
35	Total Rev Reqt $ / MCF			1 02	6 15	2 47	7 35	7 16	9 82	7 89	5 76	2 94
36	Equalized Total Revenue			9,990	62,898	4,228	26,623	72,888	30,851	31,390	3,627	7,019
37	Present Total Revenue			8,309	63,298	3,231	24,612	71,607	27,842	32,509	3,918	7,338
38	Revenue Deficiency			1,681	-400	998	2,011	1,281	3,009	-1,119	-291	-319
39	Deficiency / Pres Rev			20 23%	-18 44%	122 25%	-111 44%	1 79%	10 81%	-3 44%	-7 42%	-4 35%

Plant in Service

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	P10	Design Day	0	1,660	0	741	**1,660**	741	919	0	0
	Storage Plant											
2	LNG Storage	P20	Design Day	0	3,396	0	1,516	**3,396**	1,516	1,880	0	0
	Transmission Plant											
3	Transmission Plant	P30	Average and Peak	0	3,142	0	1,232	**3,142**	1,232	1,529	71	309
	Distribution Plant											
4	Regulator Stations	P41	Average and Peak	0	558	0	219	558	219	272	13	55
	Mains - Minimum System	P42A	Customers	20,828	0	17,627	0	20,828	17,627	3,133	56	12
5	Mains - Average Capacity	P42B	Average Day (Sales)	0	3,323	0	1,025	3,323	1,025	1,290	209	799
6	Mains - Excess Capacity	P42C	Excess Design Day	0	5,904	0	2,594	5,904	2,594	3,201	0	109
7	Mains - Total	P42		20,828	9,227	17,627	3,619	30,055	21,246	7,624	266	920
8	Services	P43	Serv Study	20,674	0	15,423	0	20,674	15,423	4,934	233	84
9	Meters	P44	Meter Study	7,981	0	3,551	0	7,981	3,551	4,089	232	109
10	House Regulators	P45	Regul Study	963	0	618	0	963	618	325	7	13
11	**Total**	**P40**		50,446	9,785	**37,219**	**3,838**	**60,231**	**41,057**	**17,243**	**751**	**1,180**
12	**Plant in Service w/o Gen and Com**	**P60**		**50,446**	**17,983**	**37,219**	**7,327**	**68,429**	**44,547**	**21,571**	**822**	**1,489**
	General Plant											
13	General Plant	**P70**	P60	1,235	440	803 85	286 56	**1,675**	**1,090 41**	**528**	**20**	**36**
	Common Plant											
14	Common Plant	**P80**	P60	3,638	1,297	2,368	844	**4,935**	**3,213**	**1,556**	**59**	**107**
15	Prelim Gas Plant	GPISA		55,319	19,720	40,392	8,458	75,039	48,850	23,655	901	1,633
16	TBT Investment	PTBT	Net Plant	2	0	1	0	2	1	1	0	0
17	**Gas Plant in Serv**	**GPIS**		**55,320**	**19,721**	**40,393**	**8,459**	**75,041**	**48,851**	**23,656**	**901**	**1,633**

Accumulated Depreciation Reserve

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	A10	Design Day	0	1,213	0	542	1,213	542	671	0	0
	Storage Plant											
2	LNG Storage	A20	Design Day	0	2,439	0	1,089	2,439	1,089	1,350	0	0
	Transmission Plant											
3	Transmission Plant	A30	Average and Peak	0	1,721	0	675	1,721	675	838	39	169
	Distribution Plant											
4	Regulator Stations	A41	Average and Peak	0	136	0	53	136	53	66	3	13
5	Mains	A42	Mains overall	8,211	3,638	5,805	2,572	11,849	8,376	3,006	105	363
6	Services	A43	Serv Study	8,646	0	6,450	0	8,646	6,450	2,063	98	35
7	Meters	A44	Meter Study	2,691	0	1,197	0	2,691	1,197	1,379	78	37
8	House Regulators	A45	Regul Study	423	0	271	0	423	271	143	3	6
9	**Total**	A40		**19,971**	**3,774**	**13,723**	**2,625**	**23,745**	**16,348**	**6,657**	**287**	**453**
10	**Accum Depr w/o Gen and Com**	A60		**19,971**	**9,147**	**13,723**	**4,930**	**29,118**	**18,654**	**9,516**	**326**	**623**
	General Plant											
11	General Plant	A70	A60	**665**	**304**	**426**	**195**	**969**	**621**	**317**	**11**	**21**
	Common Plant											
12	Common Plant	A80	A60	**1,780**	**815**	**1,140**	**522**	**2,595**	**1,662**	**848**	**29**	**55**
13	**Total Accum Depr**	**APD**		**22,416**	**10,266**	**15,289**	**5,648**	**32,682**	**20,937**	**10,681**	**366**	**699**
14	**Net Gas Plant Before TBT**	**NGPISA**		**32,903**	**9,454**	**25,102**	**2,811**	**42,357**	**27,913**	**12,974**	**536**	**934**
15	**Net Plant With TBT**	**NGPIS**		**32,905**	**9,454**	**25,103**	**2,811**	**42,359**	**27,914**	**12,975**	**536**	**934**

Subtractions to Net Plant (Page 1 of 1)

	Accum Defer Inc Tax											
	Production Plant	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
1	LPG Production Plant	DT10	Design Day	0	28	0	12	28	12	16	0	0
	Storage Plant											
2	LNG Storage	DT20	Design Day	0	155	0	69	155	69	86	0	0
	Transmission Plant											
3	Transmission Plant	DT30	Average and Peak	0	241	0	95	**241**	95	117	5	**24**
	Distribution Plant											
4	Regulator Stations	DT41	Average and Peak	0	48	0	19	48	19	23	1	5
5	Mains	FT42	Mains overall	1,789	793	1,265	560	2,582	1,825	655	23	79
6	Services	DT43	Serv Study	1,777	0	1,325	0	1 777	1,325	424	20	7
7	Meters	DT44	Meter Study	686	0	305	0	686	305	351	20	9
8	House Regulators	DT45	Regul Study	83	0	53	0	83	53	28	1	1
9	**Total**	**DT40**		4,334	841	**2,948**	**579**	**5,175**	**3,528**	**1,482**	**65**	**101**
10	**ADIT w/o Gen & Com**	**DT60**				**2,948**	**755**	**5,599**	**3,704**	**1,700**	**70**	**125**
	General Plant											
11	General Plant	**DT70**	DT60	**147**	43	97	28	**190**	**126**	**58**	**2**	**4**
	Common Plant											
12	Common Plant	**DT80**	DT60	382	**111**	252	74	**493**	**326**	**150**	**6**	**11**
	Adjustments											
13	Accum Def Tax - TBT	DTTBT	Net Plant	21	6	13 6	3 9	26 5	17	8	0	1
14	Non-Plant Related	DTTTD	Labor	(280)	-85	-192	-58	-366	-251	-97	-8	-10
15	**Total Inc Tax Lib Depr**	**DT00**		4,603	1,340	**3,120**	**803**	**5,943**	**3,922**	**1,819**	**70**	**131**
16	**Total Subtractions**	**ADT**		4,603	1,340	**3,120**	**803**	**5,943**	**3,922**	**1,819**	**70**	**131**

Additions to Net Plant (Pg 1 of 2)

	CWIP	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production	CP10	Design Day	0	38	0	17	38	17	21	0	0
2	LNG Storage Plant	CP20	Design Day	0	52	0	23	52	23	29	0	0
3	Transmission Plant	CP31	Average and Peak	0	11	0	4	11	4	5	0	1
4	Distribution Plant Mains	CP42	Mains overall	0	0	0	0	0	0	0	0	0
5	General Plant Distribution	CP54	Dist Plant	0	0	0	0	0	0	0	0	0
6	Common Plant Distribution	CP64	Dist Plant	0	0	0	0	0	0	0	0	0
7	**Total CWIP**	**CWIP**		0	101	0	44	101	44	55	0	1
	Materials & Supplies											
8	Materials and Supplies	MSP	Trans+Dist	150	38	100	26	188	125	56	2	4
	Gas In Storage											
9	LPG In Storage	MSGPN	Sales	0	272	0	84	272	84	106	17	65
10	LNG In Storage	MSGPM	Sales	0	499	0	154	499	154	194	31	120
11	NatGas Underground	SMGN	Sales	0	3,063	0	945	3,063	945	1,189	193	736
12	**Total**	**MSG**		**0**	**3,834**	**0**	**1,182**	**3,834**	**1,182**	**1,488**	**242**	**922**
	Non-Plant Assets & Liab											
13	Pension Liability	NON1	Labor	0	0	0	0	0	0	0	0	0
14	Accrued Vacation Reserve	NON2	Labor	0	0	0	0	0	0	0	0	0
15	Early Retirement Amortization	NON3	Labor	0	0	0	0	0	0	0	0	0
16	SFAS 106	NON4	Labor	0	0	0	0	0	0	0	0	0
17	SFAS 112	NON5	Labor	0	0	0	0	0	0	0	0	0
18	Deferred Gas Costs	NON6	Labor	0	0	0	0	0	0	0	0	0
19	All Other Adjustments	NON7	Labor	(440)	-134	-302	-92	-574	-394	-152	-13	-15
20	**Total Non-Plt Assets & Liab**	**NON**		(440)	-134	-302	-92	-574	-394	-152	-13	-15

Additions to Net Plant (Pg 2 of 2)

	Miscellaneous	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Prepay Insurance	PPI	Trans+Dist	68	17	45	12	85	57	25	1	2
2	Prepay Gas Reserv Fee	PPG	Design Day	0	1,181	0	527	1,181	527	654	0	0
3	Prepay Miscellaneous	PPM	Trans+Dist	35	9	23	6	44	29	13	1	1
4	Rate Case Exp Amort	RCAS	Pres Rev, Rev	0	0	0	0	0	0	0	0	0
5	Inc Tax Defer Inter Amort	ITD		0	0	0	0	0	0	0	0	0
6	Project 2000 Amortization	P2000		0	0	0	0	0	0	0	0	0
7	Customer Advances	CAD	Sales	0	-16	0	-5	-16	-5	-6	-1	-4
8	Other Working Capital	RCWO	Pres Rev, Rev	223	1,465	86	567	1,688	653	763	94	178
9	**Total**	**MISC**		**325**	**2,657**	**155**	**1,107**	**2,982**	**1,262**	**1,449**	**95**	**177**
	Working Cash											
10	Purchase Gas Exp - Commodity	WC11	Sales	0	-367	0	-113	-367	-113	-143	-23	-88
11	Purchase Gas Exp - Demand	WC12	Design Day	0	-60	0	-27	-60	-27	-33	0	0
12	Labor - Regular	WC13	Oper & Maint	(0)	-7	0	-3	-7	-3	-3	0	-1
13	Labor - Incentive Compensation	WC14	Oper & Maint	(0)	-4	0	-2	-5	-2	-2	0	-1
14	Pension and Benefits	WC15	Labor	(1)	0	-1	0	-2	-1	-1	0	0
15	Payroll Taxes	WC16	Labor	(0)	0	0	0	-1	0	0	0	0
16	Other Operating Expenses	WC17	Oper & Maint	(1)	-16	0	-6	-17	-7	-7	-1	-2
17	Property Taxes	WC18	Origl Plant	(47)	-17	-31	-11	-64	-42	-20	-1	-1
18	Gross Receipts Tax	WC19	Fees, Rev	0	-13	0	-5	-13	-5	-6	-1	-1
19	Federal Income Tax	WC20	Rt Bas w/o WC	(2)	-1	-1	0	-2	-1	-1	0	0
20	State Income Tax	WC21	Rt Bas w/o WC	(0)	0	0	0	0	0	0	0	0
21	State Sales Tax	WC22	Pres Rev, Rev	(1)	-9	-1	-4	-11	-4	-5	-1	-1
22	**Total Working Cash**	**WCASH**		**(54)**	**-495**	**-35**	**-171**	**-649**	**-206**	**-221**	**-27**	**-95**
23	**Total Additions**	**ADDIT**		**(20)**	**6,002**	**-82**	**2,096**	**5,982**	**2,014**	**2,675**	**299**	**994**
24	**Total Rate Base**	**BASE**		**28,282**	**14,116**	**21,902**	**4,104**	**42,398**	**26,008**	**13,831**	**764**	**1,797**
25	Customer Component							28,282	20,714	7,136	306	126
26	Capacity Component							9,542	3,886	4,822	156	677
27	Commod Component							7,924	1,406	1,877	302	995

Operating Revenue (Cal Month)

	Retail Revenue	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	**Present Retail Rev**	**R01**	**Direct**	8,262	60,579	3,197	23,440	**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
2	**Proposed Retail Rev**	**R01P**	**Direct**	8,963	61,152	3,525	24,052	**70,115**	**27,577**	**30,886**	**3,939**	**7,713**
3	Gross Reciept taxes	R04	**Direct**	0	0	0	0	**0**	0	0	0	0
4	Proposed Transportation	R05	Net Plant	0	0	0	0	0	0	0	0	0
5	Interdepart'l - Angus Anson	R06	Design Day	0	0	0	0	0	0	0	0	0
4	**Total Rate Rev Present**	**R10**		**8,262**	**60,579**	**3,197**	**23,440**	**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
5	**Total Rate Rev Proposed**	**R10P**		**8,963**	**61,152**	**3,525**	**24,052**	**70,115**	**27,577**	**30,886**	**3,939**	**7,713**
	Other Operating Rev											
8	Late Pay Penalties	R21	Present Revenues	0	131	0	51	131	51	59	7	14
9	Penalties - Non-Curtailment	R22	Sales	0	0	0	0	0	0	0	0	0
10	Connection Charges	R23	Customers	45	0	38	0	45	38	7	0	0
11	Return Check Charges	R24	Customers	2	0	2	0	2	2	0	0	0
12	Gross Reciept Taxes	R25	Direct	0	979	0	403	979	403	446	62	67
13	Gas Agreement	R28	Design Day	0	26	0	12	26	12	14	0	0
14	Locating Services	R29	Dist Expen	0	0	0	0	0	0	0	0	0
15	Balancing Services	R30	Sales	0	30	0	9	30	9	12	2	7
16	Ltd Firm Sales - Rsrvs & Vols	R31	Design Day	0	37	0	17	37	17	20	0	0
17	Standy Sales - Rsrvs & Vols	R32	Design Day	0	0	0	0	0	0	0	0	0
18	LP Sales to Others - MN	R33	Design Day	0	0	0	0	0	0	0	0	0
19	Off-System Sales	R34	Design Day	0	0	0	0	0	0	0	0	0
20	Opportunity Sales	R35	Design Day	0	1,475	0	658	1,475	658	817	0	0
21	Contr In Aid Cons Tax Gross-Up	R36	CWIP	0	0	0	0	0	0	0	0	0
22	Other - Miscellaneous	R37	DsnDay+Sales	0	41	0	15	41	15	19	1	5
23	**Tot Other Op - Present**	**R20**		**47**	**2,719**	**40**	**1,165**	**2,766**	**1,205**	**1,395**	**73**	**93**
24	**Tot Oper Rev - Present**	**R00**		**8,309**	**63,298**	**3,236**	**24,606**	**71,607**	**27,842**	**32,509**	**3,918**	**7,338**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Commodity	OXPGE	Direct	0	47,130	0	16,607	47,130	**16,607**	**20,834**	**3,272**	**6,417**
2	Demand	OXPGD	Direct	0	8,695	0	3,871	8,695	3,871	4,824	0	0
3	Other Purchased Gas	OXOPG	Sales	0	0	0	0	0	0	0	0	0
4	Opportunity Sales	OXOSN	Design Day	0	1,424	0	636	1,424	636	788	0	0
5	Limited Firm	OXANG	Design Day	0	18	0	8	18	8	10	0	0
6	**Total Purchases**	**OXPG**		0	57,267	**0**	**21,122**	**57,267**	**21,122**	**26,456**	**3,272**	**6,417**
	Other Production Exp											
7	Gas Agreement - NSP(W)	OXOSA	Design Day	0	0	0	0	0	0	0	0	0
8	MGP	OXOSSN	Sales	0	360	0	111	360	111	140	23	87
9	Misc LPG Op Exp	OXLPN	Design Day	0	143	0	64	143	64	79	0	0
10	Misc LNG Op Exp	OXLPM	DsnDay+Sales	0	221	0	83	221	83	104	7	27
11	**Total Other Prod Exp**	**OXOP**		0	724	**0**	**258**	**724**	**258**	**323**	**30**	**113**
	Other Transmission Expense											
12	Other Trans Expense	OX30	Average and Peak	0	96	0	38	96	38	47	2	9
	Distribution Expense											
13	Regulator Stations	OX41	Average and Peak	0	42	0	16	42	16	20	1	4
14	Mains	OX42	Mains overall	192	85	136	60	277	196	70	2	8
15	Services	OX43	Serv Study	203	0	151	0	203	151	48	2	1
16	Meters	OX44	Meter Study	225	0	100	0	225	100	115	7	3
17	House Regulators	OX45	Regul Study	28	0	18	0	28	18	9	0	0
18	Other Property & Equip	OX46	Customers	1	0	1	0	1	1	0	0	0
19	Dispatching	OX47	DsnDay+Sales	0	86	0	32	86	32	40	3	10
20	Customer Installations	OX48	Customers	392	0	332	0	392	332	59	1	0
21	Other Distribution	OX49	Customers	240	0	203	0	240	203	36	1	0
22	Supervision & Engineering	OX50	DisExp w/o Sup	146	24	102	17	170	119	45	2	3
23	**Total Distribution**	**OX40**		1,427	237	**1,043**	**126**	**1,664**	**1,169**	**445**	**19**	**31**

Operation & Maintenance (Pg 2 of 2)

	Customer Accounting	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Customer Billing Exp	OXBE	Customers	1,142	0	967	0	1,142	967	172	3	1
2	Customer Acct Exp	OXCA	Customers	58	0	49	0	58	49	9	0	0
3	Customer Service & Info	OXSI	Customers	22	0	19	0	22	19	3	0	0
4	**Total**	**OXCASI**		1,222	0	**1,034**	**0**	**1,222**	**1,034**	**184**	**3**	**1**
	Admin & General											
5	Property Insurance	OXAGPI	Net Plant	37	10	24	7	47	31	14	1	1
6	Pension and Benefits - ESOP	OXAGPS	Labor	0	0	0	0	0	0	0	0	0
7	Pension and Benefits - Direct	OXAGBL	Labor	414	126	284	86	540	370	143	13	14
8	Incentive Compensation	OXAGB	Labor	76	23	52	16	99	68	26	2	3
9	Injuries and Claims	OXAGID	Plant+Reven	0	115	0	60	115	60	44	4	7
10	Regulation Expense	OXAGR	Pres Rev, Rev	2	15	1	6	17	7	8	1	2
11	Promotional Adv / Contrib Adj	OXADV	Plant+Reven	0	36	0	19	36	19	14	1	2
12	Direct Assigned	OXDIR	Plant+Reven	0	191	0	99	191	99	73	6	12
13	Misc Labor Adjustments	OXAGBS	Labor	337	102	231	70	439	301	116	10	11
14	Non-Regulated Exp Credits	OXCRED	Plant+Reven	0	-26	0	-13	-26	-13	-10	-1	-2
15	**Total A & G Expense**	**OXAG**		**866**	**592**	**592**	**349**	**1,458**	**941**	**429**	**37**	**51**
	Amortizations											
16	CIP / DSM Amortization	OXCIP	Sales MCF	0	0	0	0	0	0	0	0	0
17	MN Energy Policy Rider	OXCLN	Sales MCF	0	0	0	0	0	0	0	0	0
18	Rate Case Exp Amort	RCA	Pres Rev, Rev	3	17	1	7	20	8	9	1	2
19	Inc Tax Defer Inter Amort	ITDA	Rt Bas w/o WC	0	0	0	0	0	0	0	0	0
20	Project 2000 Amortization	P2A	Plant+Reven	0	0	0	0	0	0	0	0	0
21	**Total Amortizations**	**OXC**		**3**	**17**	**1**	**7**	**20**	**8**	**9**	**1**	**2**
	Sales Expense											
22	Gross Sales Expense	OXSALX	Sales Exp Study	0	131	0	57	131	57	10	53	11
23	Sales Expen Exlcusions	OXSEE	Sales Exp Study	0	0	0	0	0	0	0	0	0
24	Economic Develop @50%	OXSED	DsnDay+Sales	0	0	0	0	0	0	0	0	0
25	Other Misc - TBT	OXTBT	Net Plant	0	0	0	0	0	0	0	0	0
26	**Total**	**OXSE**		**0**	**131**	**0**	**57**	**131**	**57**	**10**	**53**	**11**
27	**Total O&M Expense**	**OXT**		**3,517**	**59,065**	**2,671**	**21,956**	**62,582**	**24,627**	**27,903**	**3,417**	**6,635**

Book Depreciation

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	DX10	Design Day	0	37	0	17	37	17	20	0	0
	Storage Plant											
2	LNG Storage	DX20	Design Day	0	64	0	29	64	29	35	0	0
	Transmission Plant											
6	Transmission Plant	DX30	Average and Peak	0	95	0	37	95	37	46	2	9
	Distribution Plant											
7	Regulator Stations	DX41	Average and Peak	0	18	0	7	18	7	9	0	2
8	Mains	DX42	Mains overall	645	286	456	202	931	658	236	8	28
9	Services	DX43	Serv Study	580	0	433	0	580	433	138	7	2
10	Meters	DX44	Meter Study	318	0	141	0	318	141	163	9	4
11	House Regulators	DX45	Regul Study	21	0	13	0	21	13	7	0	0
12	Lakes Area Surcharge	DX46	Dist Plant	0	0	0	0	0	0	0	0	0
13	**Total**	**DX40**		**1,563**	**304**	**1,043**	**209**	**1,867**	**1,252**	**553**	**25**	**37**
14	**Depreciation Expense w/o Com & Gen**	**DX60**		**1,563**	**500**	**1,043**	**291**	**2,063**	**1,335**	**655**	**27**	**47**
	General Plant											
15	General Plant	**DX70**	DX60	84	27	54	17	**111**	**72**	**35**	**1**	**3**
	Common Plant											
16	Common Plant	**DX80**	DX60	397	127	257	82	**524**	**339**	**166**	**7**	**12**
17	**Total Book Deprec**	**DX00**		**2,044**	654	**1,354**	**391**	**2,698**	**1,745**	**857**	**35**	**61**

Real Estate & Property Taxes

	Production Plant-	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PT10	Design Day	0	37	0	16	37	16	20	0	0
	Storage Plant											
2	LNG Storage	PT20	Design Day	0	75	0	34	75	34	42	0	0
	Transmission Plant											
3	Transmission Plant	PT30	Average and Peak	0	37	0	15	37	15	18	1	4
	Distribution Plant											
4	Regulator Stations	PT41	Average and Peak	0	8	0	3	8	3	4	0	1
5	Mains	PT42	Mains overall	292	129	206	91	421	298	107	4	13
6	Services	PT43	Serv Study	290	0	216	0	290	216	69	3	1
7	Meters	PT44	Meter Study	112	0	50	0	112	50	57	3	2
8	House Regulators	PT45	Regul Study	13	0	9	0	13	9	5	0	0
9	Other Prop & Equip	PT46	Dist Plant	0	0	0	0	0	0	0	0	0
10	**Total**	PT40		707	137	**481**	**94**	**844**	**575**	**242**	**11**	**17**
11	Real Est & Prop Taxes w/o Gen & Com	PT60		707	286	**481**	159	**993**	**640**	**322**	**11**	**20**
	General Plant											
12	General Plant	PT70	PT60	**2**	1	1	0	**2**	**2**	**1**	**0**	**0**
	Common Plant											
13	Common Plant	**PT80**	PT60	5	2	3	1	**7**	**5**	**2**	**0**	**0**
14	**Tot RI Est & Pr Tax**	**PT0**		714	289	**485**	**161**	**1,002**	**646**	**325**	**11**	**20**
15	Gross Earnings Tax	GETX	Direct	0	979	0	403	979	403	446	62	67
16	Payroll Taxes	Z00	Labor	125	38	86	26	163	112	43	4	4
17	**Tot Non-Income Taxes**	**PTOT**		839	1,306	**571**	**590**	**2,144**	**1,161**	**814**	**78**	**92**

Provision For Deferred Income Taxes

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PR10	Design Day	0	-3	0	-1	-3	-1	-2	0	0
	Storage Plant											
2	LNG Storage	PR20	Design Day	0	21	0	9	21	9	12	0	0
	Transmission Plant											
3	Transmission Plant	PR30	Average and Peak	0	83	0	33	83	33	40	2	8
	Distribution Plant											
4	Regulator Stations	PR41	Average and Peak	0	5	0	2	5	2	3	0	1
5	Mains	PR42	Mains overall	198	87	140	62	285	201	72	3	9
6	Services	PR43	Serv Study	196	0	146	0	196	146	47	2	1
7	Meters	PR44	Meter Study	76	0	34	0	76	34	39	2	1
8	House Regulators	PR45	Regul Study	9	0	6	0	9	6	3	0	0
9	**Total**	**PR40**		478	93	**325**	**64**	**571**	**389**	**163**	**7**	**11**
10	**Provision w/o Gen & Com**	PR60			672	325	105	672	430	214	9	19
	General Plant											
11	General Plant	PR70	PR60	(14)	-5	-9	-4	-19	-12	-6	0	-1
	Common Plant											
12	Common Plant	PR80	PR60	32	13	20	8	45	29	14	1	1
	Other											
13	All Other Adjustments	PR77	Labor	(90)	-27	-62	-19	-117	-80	-31	-3	-3
	Total Other	**PR70**			-117	**-62**	-19	**-117**	**-80**	**-31**	**-3**	**-3**
14	**Tot Prov For Defer**	**PR0**		407	174	**276**	**91**	**581**	**366**	**191**	**7**	**17**

Investment Tax Credit For Current Income

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	CI10	Design Day	0	0	0	0	0	0	0	0	0
	Storage Plant											
2	LNG Storage	CI20	Design Day	0	-1	0	0	-1	0	-1	0	0
	Transmission Plant											
3	Transmision Plant	CI30	Average and Peak	0	-2	0	-1	-2	-1	-1	0	0
	Distribution Plant											
6	Regulator Stations	CI41	Average and Peak	0	0	0	0	0	0	0	0	0
7	Mains	CI42	Mains overall	(9)	-4	-6	-3	-13	-9	-3	0	0
8	Services	CI43	Serv Study	(10)	0	-7	0	-10	-7	-2	0	0
9	Meters	CI44	Meter Study	(4)	0	-2	0	-4	-2	-2	0	0
10	House Regulators	CI45	Regul Study	(0)	0	0	0	0	0	0	0	0
11	**Total**	**CI40**		(23)	-4	-15	-3	-27	-18	-8	0	-1
12	ITC w/o gen and Com	CI60	subtotal	**(23)**	**-7**	**-15 46**	**-4 15**	**-30**	**-19 61**	**-9**	**0**	**-1**
	General Plant											
13	General Plant	CI70	CI60	0	0	0	0	**0**	**0**	**0**	**0**	**0**
	Common Plant											
14	Common Plant	CI80	CI60	0	0	0	0	**0**	**0**	**0**	**0**	**0**
15	**Tot ITC For Curr Inc**	**CI00**		(23)	-7	**-15 46**	**-4 15**	**-30**	**-19 61**	**-9**	**0**	**-1**
16	**Gross Inv Tax Credit**	**DI5**		0	0	0	0	**0**	**0**	**0**	**0**	**0**
17	**Net Inv Tax Credit**	**DI00**		**(23)**	**-7**	**-15 46**	**-4 15**	**-30**	**-19 61**	**-9**	**0**	**-1**
18	**Total Operating Exp**	**TOE**		**6,784**	**61,191**	**4,856**	**23,024**	**67,975**	**27,880**	**29,755**	**3,536**	**6,804**
19	**Op Inc Before Inc Tax**	**OPY**		**1,524**	**2,107**	**-1,620**	**1,582**	**3,632**	**-38**	**2,753**	**382**	**534**

Tax Depreciation & Removal Exp Generated

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	TA10	Design Day	0	36	0	16	36	16	20	0	0
	Storage Plant											
2	LNG Storage	TA20	Design Day	0	118	0	53	118	53	65	0	0
	Transmission Plant											
3	Transmission Plant	TA30	Average and Peak	0	317	0	124	**317**	124	154	7	31
	Distribution Plant											
4	Regulator Stations	TA41	Average and Peak	0	34	0	13	34	13	16	1	3
5	Mains	TA42	Mains overall	1,261	559	892	395	1,820	1,287	462	16	56
6	Services	TA43	Serv Study	1,252	0	934	0	1,252	934	299	14	5
7	Meters	TA44	Meter Study	483	0	215	0	483	215	248	14	7
8	House Regulators	TA45	Regul Study	58	0	37	0	58	37	20	0	1
9	Other Property & Equip	TA46	Dist Plant	0	0	0	0	0	0	0	0	0
10	**Total**	**TA40**		3,054	593	**2,078**	**408**	**3,647**	**2,486**	**1,044**	**45**	**71**
11	**Tax Depreciation w/o Gen & Com**	**TA60**	Subtotal	3,054	1,064	**2,078**	**601**	**4,118**	**2,679**	**1,284**	**53**	**103**
	General Plant											
12	General Plant	TA70	TA60	**81**	28	53	18	**109**	**71**	**34**	**1**	**3**
	Common Plant											
13	Common Plant	TA80	TA60	417	145	271	94	**562**	**366**	**175**	**7**	**14**
14	Tax Benefit Transfers	TATBT	Net Plant	(97)	-28	-64	-18	-125	-82	-38	-2	-3
15	**Total Tax Depreciation**	**TA00**		3,455	1,209	**2,338**	**696**	**4,664**	**3,033**	**1,454**	**60**	**117**

Present Return

	Inc Tax Additions	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Total Book Depr Exp	DX00		2,044	654	1,323	423	2,698	1,745	857	35	61
2	Book Dep Cleared To Operating	DX99	Book Deprec	59	19	38	12	78	50	25	1	2
3	Provision for Deferred	PRO		407	174	257	110	581	366	191	7	17
4	Net Inv Tax Credit	DI00		(23)	-7	-15	-5	-30	-20	-9	0	-1
5	Book Amortizations	NDDI	Net Plant	16	4	10	3	20	13	6	0	0
6	Connect Fees and Other	ND2B	Customers	81	0	69	0	81	69	12	0	0
7	Avoided Tax Interest	ND2ASP	CWIP	0	106	0	47	106	47	58	0	1
8	Tax Capitalized Leases	NDTC	Plant	0	0	0	0	0	0	0	0	0
9	Meals & Entertainment	NDME	Labor	2	1	2	0	3	2	1	0	0
10	TBT Net Expense	NDTBT	Net Plant	0	0	0	0	0	0	0	0	0
11	**Total Tax Additions**			**2,586**	**951**	**1,683**	**590**	**3,537**	**2,273**	**1,140**	**43**	**81**
	Inc Tax Deductions											
12	Tax Depr & Removal Exp	TA00		3,455	1,209	2,338	696	4,664	3,033	1,454	60	117
13	Debt Interest Expense	ND1	Rate Base	1,033	516	800	150	1,548	950	505	28	66
14	Other Timing Differerences	PRMPAG	Labor	(58)	-17	-39	-12	-75	-51	-20	-2	-2
15	Net Preferred Stock Deduction	OTHLHD	Net Plant	0	0	0	0	0	0	0	0	0
16	**Total**			**4,430**	**1,707**	**3,098**	**834**	**6,137**	**3,932**	**1,940**	**86**	**180**
17	**Taxable Net Income**	FSNI		(320)	1,351	**-3,035**	**1,339**	**1,031**	**-1,696**	**1,954**	**339**	**434**
18	**Inc Tax (Pre-Credits), @39 55%**	TAX		**(126)**	**534**	**-1,200**	**529**	**408**	**-671**	**773**	**134**	**172**
19	**Tax Credits**				0	0	0	0	0	0	0	0
20	**Fed & State Inc Tax**	**TAXES**		**(126)**	**534**	**-1,200**	**529**	**408**	**-671**	**773**	**134**	**172**
21	**Total AFUDC**	**AFC**	**CWIP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
22	**Pres Return**	**RETR**	**,BASE**	**1,651**	**1,573**	**-419**	**1,053**	**3,224**	**633**	**1,980**	**248**	**362**
23	**Pres Return on Rate Base**	**RTRT**		**5 84%**	**11 14%**	**1 87%**	**25 65%**	**7 60%**	**2 43%**	**14 32%**	**32 43%**	**20 16%**

Labor Allocator

							336,490		
	Labor Components	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
24	Customer Billing	LAB1	Wtd Customer	3 4%	2 8%	0 5%	0 1%	0 0%
25	Customer Accounting	LAB2	Customer	10 8%	9 2%	1 6%	0 0%	0 0%
26	Cust Serv & Inform	LAB3	Customer	2 3%	2 0%	0 3%	0 0%	0 0%
27	Distribution	LAB4	Dist Expen	70 2%	49 3%	18 8%	0 8%	1 3%
28	Gas Storage - LNG	LAB5	DsnDay+Sales	5 4%	2 0%	2 5%	0 2%	0 6%
29	Production	LAB6	Other Produc	2 6%	0 9%	1 1%	0 1%	0 4%
30	Sales	LAB7	Sales Exp Study	2 9%	1 3%	0 2%	1 2%	0 2%
31	Transmission	LAB8	Design Day	2 4%	1 1%	1 4%	0 0%	0 0%
32	**Total**	LABOR		100 0%	68 6%	26 5%	2 3%	2 6%

EXTERNAL ALLOCATORS			ND	Res	Sm C/I	Sm Int	Lg Int
Customer Related							
1 Customers - B Basis	C10	40,827	40,827	34,553	6,141	110	23
%1 Customers - B Basis	C10		100 00%	84 63%	15 04%	0 27%	0 06%
2 Service Weighting (index)	C20			1 00	1 80	4 75	8 19
2 Weighted Service	C20		46,318	34,553	11,054	523	188
%2 Services Factor	C20		100 00%	74 60%	23 87%	1 13%	0 41%
3 Meter Factor Weighting (Index)	C21			1 00	6 48	20 47	45 95
3 Weighted Meter	C21		77,659	34,553	39,794	2,255	1,057
%3 Meter Factor	C21		100 00%	44 49%	51 24%	2 90%	1 36%
4 House Regulator Weighting (index)	C22			1 00	2 95	3 79	30 84
4 Weighted Regulator			53,817	34,553	18,138	418	709
%4 House Regulator Factor	C22		100 00%	64 20%	33 70%	0 78%	1 32%
5 Sale expense Weighting	E03			0 000762	0 000762	0 222279	0 222279
5 Weighted Sales Expense	E03		61	26	5	24	5
%5 Sales Expense	E03		100 00%	43 44%	7 72%	40 40%	8 44%
6 Cust Acctg Weights	C10WTS		23	1	1	6	6
6 Weighted Customers	C10W		41,493	34,553	6,141	661	138
%6 Weighted Custs (Cust Acctg)	C10W		100 000%	83 274%	14 800%	1 593%	0 333%
Main Allocator							
7 Mains - Average Day (Sales)			26,819	8,270	10,411	1,689	6,448
7 Mains - Average Day (Sales)	Load Factor =		100 00%	30 84%	38 82%	6 30%	24 04%
(Transportation adder)							
8 Mains - Excess Design Day			56,628	24,971	30,809	0	###########
8 Mains - Excess Design Day			100 00%	43 94%	54 22%	0 00%	1 84%
9 Mains Average and Peak			9,227	3,619	4,491	209	908
9 Average and Peak			100 00%	39 22%	48 67%	2 27%	9 84%
10 Mains overall			30,055	21,246	7,624	266	920
10 Mains overall			100 00%	70 69%	25 37%	0 88%	3 06%
Sales and Capacity Related							
11 Design Day	D10		74,462	33,242	41,220	0	0
11 Design Day %	D10		100 00%	44 64%	55 36%	0 00%	0 00%
12 Sales MCF	E10		9,788,919	3,018,662	3,800,041	616,604	2,353,612
12 Sales MCF	E10		100 00%	30 84%	38 82%	6 30%	24 04%
13 Sales MCF (Exc CIP exempt)	E10CIP		8,948,819	3,018,662	3,800,041	616,604	1,513,512
13 Sales MCF	E10CIP		100 00%	33 73%	42 46%	6 89%	16 91%
14 Gross Receipts	GR10		1,068,746	440,304	486,820	68,064	73,558
14 Gross Receipts	GR10		100 00%	41 20%	45 55%	6 37%	6 88%
15 CIP Allocator	GR10		3,346	0	0	0	0
15 CIP Allocator	GR10		0 00%	0 00%	0 00%	0 00%	0 00%
16 LatePayment Revenues	LPY						
16 LatePayment Revenues	LPY		100 00%	38 69%	45 20%	5 59%	10 52%
17 Present Rev			68,841	26,637	31,114	3,845	7,245
17 Present Rev	R01		100 00%	38 69%	45 20%	5 59%	10 52%

	INTERNAL ALLOCATORS		ND	Res	Sm C/I	Sm Int	Lg Int
1	Rate Base		42,398	26,006	13,831	764	1,797
%1	Rate Base	BASE-COL	100 000%	61 338%	32 622%	1 802%	4 238%
				100 000%	100 000%	100 000%	100 000%
2	Rate Base less Working Cash		39,965	24,950	12,603	696	1,715
%2	Rate Base less Working Cash	BASEWC	100 000%	62 431%	31 536%	1 742%	4 291%
			101	44	55	0	1
4	Construction Work In Progress	CWIP	100 000%	44 052%	54 629%	0 247%	1 072%
5	50% Design Day, 50% Energy	D10E10	100 000%	37 740%	47 089%	3 149%	12 022%
7	Book Depreciation	DX00	100 000%	64 694%	31 755%	1 295%	2 256%
8	50% Gross Plant, 50% Pres Rev	EGPRV	100 000%	51 896%	38 360%	3 393%	6 350%
9	Gas Plant In Service	GPIS	100 000%	65 099%	31 524%	1 201%	2 176%
9	Gas Plant In Service (w/o Gen and Common)	GPIS (B)	100 000%	65 099%	31 524%	1 201%	2 176%
10	Labor	LABOR	100 000%	68 567%	26 504%	2 325%	2 605%
11	Net Gas Plant In Svc (w/o TBT)	NGPIS(A)	100 000%	65 899%	30 631%	1 265%	2 205%
12	Dis O&M w/o Sup & Misc	OXDTS	1,494	1,050	400	17	28
12	Dist O&M (w/o Sup & Eng)	OX40(A)	100 000%	70 280%	26 746%	1 128%	1 845%
13	Other Production Expense	OXOP	100 000%	35 671%	44 610%	4 093%	15 625%
14	Oper & Maint Expense	OXT	100 000%	39 351%	44 586%	5 460%	10 602%
15	Distribution Plant	P40	100 000%	68 166%	28 628%	1 246%	1 959%
16	Transmission & Distribution	TD	63,373	42,290	18,772	822	1,489
16	Transmission & Distribution	TD	100 000%	66 731%	29 622%	1 297%	2 349%
17	Rev w/o Regul Exp, Col %'s	R02-COL	100 000%	41 918%	42 944%	5 137%	10 001%

CONSTANTS FOR REV CALCULATION

			Rate	Ratio	Wtd Cost
1	Long Term Debt		7 3300%	48 6530%	3 5663%
2	Short Term Debt		7 7400%	1 1070%	0 0857%
3	Debt Total		7 3392%	49 7600%	3 6520%
4	Preferred Stock		0 0000%	0 0000%	0 0000%
5	Common Equity		11 5000%	50 2400%	5 7776%
6	Required Rate of Return			100 0000%	9 4296%
7	MN Combined State & Fed Tax Rate	TAXRATE	0 3955000		
8	1 / (1 - Tax Rate) Factor	ONEOVER	1 6542600		
9	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	0 6542600		

Scott, Sandi L.

From: Lein, Jerry R.

Sent: Thursday, April 21, 2005 10:59 AM

To: -Grp-PSC Commissioners

Cc: -Grp-PSC Public Utilities, -Grp-PSC Legal, 'Sederquist, Dave', 'Johnson, James P

Subject: Correction and Clarification from PU-04-578 Informal Hearing

I would like to correct an error I made during the informal hearing yesterday In response to a question to commissioner Wefald I quoted incorrectly from the staff requested rerun of the class cost of service study (CCOS, now Docket #75 in the case file) a monthly residential capacity revenue component of $2 25 per customer, which I then added to the $11 91 monthly customer component to provide an incorrect monthly residential revenue requirement per customer of slightly over $14 for comparison with NSP's $17 99 When I got back to the office I discovered I had been reading the staff CCOS numbers wrong and the $2 25 I quoted was actually an annual capacity revenue requirement of $2,252,000 Converting this number to monthly revenue per customer ($2,252,000 per year / 34,553 residential customers / 12 months per year) results in a monthly capacity revenue requirement of $5 43 per residential customer. Thus the total residential revenue requirement per customer from the staff CCOS (based on NSP's originally requested $1 28 million total increase) would be $11 91 + $5 43 = $17 34

Additionally, Dave Sederquist from NSP left a message explaining that the average use per residential customer shown on the declining use per customer graph he presented equates to 88 dekatherms per year * 10 therms per dekatherm / 12 months per year = 73 therms per month

Thanks

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Correction & Clarification from 4-20-05 Informal Hearing
by Public Service Commission

04/21/2005 C Comm Legal PUD (4) Mike ALJ

INFORMAL HEARING AGENDA

April 20, 2005

PU-04-578 Northern States Power Company
Natural Gas Rate Increase
Application

Informal Hearing held

by Public Service Commission

04/20/2005 C Comm Legal PUD (4) Mike ALJ

☐ Proprietary
☒ Non-Proprietary

Northern States Power Company
Docket No. PU-400-04-578
Response To Jerry Lein, NDPSC Information Request No. 1-02
Date Received: 12/28/00

Question:
Please provide a re-run of the Schedule 9 class cost of service study without a minimum distribution system imputed and with 75% of the costs for transmission plant, regulator stations and mains allocated to the customer classes according to class average daily test-year usage while the remaining 25% of these costs are allocated according to the difference between class average and design-day test-year usage.

Response:
Attached is the Class Cost of Service Study reflecting the assumptions indicated in the request.

Response By: Nick Paluck
Title: Principal Pricing Analyst
Department: Pricing and Planning
Telephone: 612-330-1913
Date: 1/13/05

Summary Functionalized Rate Base

	Plant In Service	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Production	P10		1,660	741	919	0	0
2	Storage	P20		3,396	1,516	1,880	0	0
3	Transmission	P30		3,142	1,072	1,341	148	581
4	Distribution	P40		60,231	30,035	22,410	1,919	5,867
5	Sub-total	P60		68,429	33,364	26,550	2,067	6,448
6	General	P70		1,675	817	650	51	158
7	Common	P80		4,936	2,406	1,915	149	465
8	TBT Investment	PTBT		2	1	1	0	0
9	**Total**	PLANT		**75,041**	**36,588**	**29,116**	**2,267**	**7,071**
	Depreciation Reserve							
10	Production	A10		1,213	542	671	0	0
11	Storage	A20		2,439	1,089	1,350	0	0
12	Transmission	A30		1,721	587	734	81	318
13	Distribution	A40		23,745	12,007	8,699	745	2,294
14	Sub-total	A60		29,118	14,225	11,455	827	2,612
15	General	A70		969	473	381	28	87
16	Common	A80		2,595	1,268	1,021	74	233
17	**Total**	DEPR		**32,682**	**15,966**	**12,857**	**928**	**2,932**
18	**Net Plant With TBT**	NGPIS		42,359	20,622	16,258	1,339	4,139
	Accumulated Deferred Taxes	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
19	Production	DT10		28	12	16	0	0
20	Storage	DT20		155	69	86	0	0
21	Transmission	DT30		241	82	103	11	45
22	Distribution	DT40		5,175	2,581	1,925	165	504
23	Sub-total	DT60		5,599	2,745	2,130	176	549
24	General	DT70		180	93	72	6	19
25	Common	DT80		493	242	188	16	48
26	Non-Plant related	DT90		-339	-220	-95	-10	-15
27	**Total**	ADT		5,943	2,859	2,295	188	601
	Construction Work In Progress	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
17	Production	CP10		38	17	21	0	0
18	Storage	CP20		52	23	29	0	0
19	Transmission	CP31		11	4	5	1	2
20	Distribution	CP42		0	0	0	0	0
21	Sub-total	CP60		101	44	55	1	2
21	General	CP54		0	0	0	0	0
22	Common	CP64		0	0	0	0	0
23	Non-Plant related	CP90		0	0	0	0	0
24	**Total**	CWIP		101	44	55	1	2
	Net Investment Rate Base	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
25	Production	NIRB10		457	204	253	0	0
26	Storage	NIRB20		854	381	473	0	0
27	Transmission	NIRB30		1,191	406	508	56	220
28	Distribution	NIRB40		31,311	15,447	11,786	1,009	3,069
29	Sub-total	NIRB60		33,813	16,439	13,020	1,065	3,289
30	General	NIRB70		516	250	196	17	52
31	Common	NIRB80		1,847	897	706	60	184
32	TBT Investment			2	1	1	0	0
33	Non-Plant related	NIRB90		339	220	95	10	15
34	**Total**	NIRB		36,517	17,807	14,018	1,152	3,540
	Additions							
35	Materials & Supplies	MSP		188	92	70	6	19
36	Gas in Storage	MSG		3,834	1,182	1,488	242	922
37	Non Plant Asset & Liabilities	NON		-574	-366	-164	-16	-27
38	Prepaids and Other	MISC		2,982	1,232	1,453	99	198
39	Cash Working Capital	WCASH		-549	-195	-226	-28	-100
40	**Total**			**5,881**	**1,946**	**2,622**	**302**	**1,011**
41	**Rate Base**	**BASE**		**42,398**	**19,753**	**16,640**	**1,454**	**4,552**

Summary: Income Statement

	ND	Res	Sm C/I	Sm Int	Lg Int
Operating Revenues					
Retail	68,841	26,361	30,885	3,912	7,683
Other Operating	2,766	1,205	1,394	73	94
Total Operating Revenues	**71,607**	**27,566**	**32,279**	**3,986**	**7,777**
Expenses					
Operating Expenses					
Purchased Gas (PGA)	55,825	20,478	25,658	3,272	6,417
Purchased Gas other	1,442	644	798	0	0
Production	724	258	323	30	113
Transmission	96	33	41	5	18
Distribution	1,664	1,054	496	32	82
Customer Accounting	1,200	1,015	180	3	1
Customer Service and Information	22	19	3	0	0
Administrative and General	1,456	854	467	47	91
Amortizations	20	8	9	1	2
Sales, Econ Develop & Other	131	57	10	53	11
Total O&Ms	**62,582**	**24,419**	**27,985**	**3,442**	**6,735**
Depreciation Expense	2,698	1,293	1,059	85	262
Taxes other than Income Taxes	1,165	592	442	34	98
Deffrred incomes Taxes and ITC	551	244	223	19	65
Gross Earnings	979	403	446	62	67
Op Income before taxes	3,632	614	2,124	343	550
State and Federal Income Taxes	408	(245)	451	99	102
Total Expense	**68,383**	**26,707**	**30,606**	**3,742**	**7,328**
AFUDC	-	-	-	-	-
Total Operating Income	**3,224**	**859**	**1,673**	**244**	**448**
Rate Base	**42,398**	**19,753**	**16,640**	**1,454**	**4,552**
Return on Rate Base	**7.604%**	**4.348%**	**10.053%**	**16.759%**	**9.853%**
Return on Equity at present rates	**7.865%**	**1.386%**	**12.740%**	**26 089%**	**12 344%**
Required Rate of Return on Rate Base	**9.430%**	**9.430%**	**9.430%**	**9.430%**	**9.430%**
Required Operating Income	**3,998**	**1,863**	**1,569**	**137**	**429**
Income Deficiency	**774**	**1,004**	**-104**	**-107**	**-19**
Revenue Deficiency	**1,260**	**1,660**	**-171**	**-176**	**-32**
Percent Increase Indicated	**1.8%**	**6.0%**	**-0.5%**	**-4.4%**	**-0 4%**

Equal Rate of Return

	Total Retail Rev Reqt	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Return On Rate Base			9 43%	9 43%	9 43%	9 43%	9 43%
2	Equalized Retail Revenue			70,122	26,021	30,713	3,736	7,651
3	Present Retail Revenue			68,841	26,361	30,885	3,912	7,683
4	Revenue Deficiency			1,281	1,660	-171	-176	-32
5	Deficiency / Pres Rev			1 86%	6 30%	-0 56%	-4 51%	-0 42%
	Internal Rev Reqt							
6	Customer Rev Reqt			6,961	4,937	1,901	86	37
7	Ave Monthly Customers			40,827	34,553	6,141	110	23
8	Rev Reqt $ / Mo / Cust			14 21	11 91	25 80	65 22	132 39
9	Capacity Rev Reqt			6,194	2,252	2,810	230	902
10	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
11	Rev Reqt $ / MCF (MCF per Month)			0 63	0 75	0 74	0 37	0 38
	Capacity - Sub Classification							
12	Capacity -Base Rev Reqt			3,690	1,142	1,438	230	879
13	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
14	Rev Reqt $ / MCF			0 38	0 38	0 38	0 37	0 37
15	Capacity -Seasonal Rev Reqt			1,219	536	661	0	22
16	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
17	Rev Reqt $ / MCF			0 12	0 18	0 17	0 00	0 01
18	Peak Shaving Rev Reqt			1,285	573	711	0	0
19	Ave Monthly Customers/ (Design Day)			9,788,919	3,018,662	3,800,041	616,604	2,353,612
20	Rev Reqt $ / MCF			0 13	0 19	0 19	0 00	0 00
12	Energy Rev Reqt			1,142	355	344	148	295
10	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
13	Rev Reqt $ / MCF			0.12	0 12	0 09	0 24	0 13
14	Total Internal Rev Reqt			14,297	7,543	5,055	464	1,234
15	Rev Reqt $ / MCF			1 48	2 50	1 33	0 75	0 52
	External Rev Reqt							
16	Capacity Rev Reqt			8,695	3,871	4,824	0	0
17	Rev Reqt $ / MCF			0 89	1 28	1 27	0 00	0 00
18	Energy Rev Reqt			47,130	16,807	20,834	3,272	6,417
19	Rev Reqt $ / MCF			4 81	5 50	5 48	5 31	2 73
20	Total External Rev Reqt			55,825	20,478	25,658	3,272	6,417
21	Rev Reqt $ / MCF			5 70	6 78	6 75	5 31	2 73
	Total Rev Reqt							
22	Cust Rev Reqt $ / MCF			0 71	1 64	0 50	0 14	0 02
23	Demd Rev Reqt $ / MCF			1 52	2 03	2 01	0 37	0 38
24	Ener Rev Reqt $ / MCF			4 93	5 62	5 57	5,55	2,85
25	Total Rev Reqt $ / MCF			7 16	9 28	8 08	6 06	3 25
26	Equalized Total Revenue			72,888	29,226	32,108	3,809	7,745
27	Present Total Revenue			71,607	27,566	32,279	3,986	7,777
28	Revenue Deficiency			1,281	1,660	-171	-176	-32
29	Deficiency / Pres Rev			1 79%	6 02%	-0 53%	-4 42%	-0 41%

Plant in Service

		Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
	Production Plant							
1	LPG Production Plant	P10	Design Day	1,660	741	919	0	0
	Storage Plant							
2	LNG Storage	P20	Design Day	3,396	1,516	1,880	0	0
	Transmission Plant							
		75%		2,356 50	727	915	148	567
		25%		785 50	345	426	0	14
3	Transmission Plant	P30	Average and Peak	3,142	1,072	1,341	148	581
	Distribution Plant							
		75%		419	129	162	26	101
		25%		140	61	76	0	3
4	Regulator Stations	P41	Average and Peak	558	190	238	26	103
	Mains - Minimum System	P42A	Customers	0	0	0	0	0
5	Mains - Average Capacity	P42B	Average Day (Sales)	22,541	6,951	8,750	1,420	5,420
6	Mains - Excess Capacity	P42C	Excess Design Day	7,514	3,302	4,074	0	138
7	Mains - Total	P42		30,055	10,253	12,824	1,420	5,558
8	Services	P43	Serv Study	20,674	15,423	4,934	233	84
9	Meters	P44	Meter Study	7,981	3,551	4,089	232	109
10	House Regulators	P45	Regul Study	963	618	325	7	13
11	**Total**	**P40**		**60,231**	**30,036**	**22,410**	**1,919**	**5,867**
12	**Plant in Service w/o Gen and Com**	**P60**		**68,429**	**33,364**	**26,550**	**2,067**	**6,448**
	General Plant							
13	General Plant	P70	P60	1,675	817	650	51	158
	Common Plant							
14	Common Plant	P80	P60	4,935	2,406	1,916	149	465
15	Prelim Gas Plant	GPISA		75,039	36,587	29,114	2,267	7,071
16	TBT Investment	PTBT	Net Plant	2	1	1	0	0
17	**Gas Plant in Serv**	**GPIS**		**75,041**	**36,588**	**29,115**	**2,267**	**7,071**

Accumulated Depreciation Reserve

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	A10	Design Day	1,213	542	671	0	0
	Storage Plant							
2	LNG Storage	A20	Design Day	2,439	1,089	1,350	0	0
	Transmission Plant							
3	Transmission Plant	A30	Average and Peak	1,721	587	734	81	318
	Distribution Plant							
4	Regulator Stations	A41	Average and Peak	136	46	58	6	25
5	Mains	A42	Mains overall	11,849	4,042	5,056	560	2,191
6	Services	A43	Serv Study	8,646	6,450	2,063	98	35
7	Meters	A44	Meter Study	2,691	1,197	1,379	78	37
8	House Regulators	A45	Regul Study	423	271	143	3	6
9	Total	A40		23,745	12,007	8,699	745	2,294
10	Accum Depr w/o Gen and Com	A60		29,118	14,225	11,455	827	2,612
	General Plant							
11	General Plant	A70	A60	969	473	381	28	87
	Common Plant							
12	Common Plant	A80	A60	2,595	1,268	1,021	74	233
13	Total Accum Depr	APD		32,682	15,966	12,857	928	2,932
14	Net Gas Plant Before TBT	NGPISA		42,357	20,621	16,258	1,339	4,139
15	Net Plant With TBT	NGPIS		42,359	20,622	16,258	1,339	4,139

Subtractions to Net Plant (Page 1 of 1)

	Accum Defer Inc Tax	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
	Production Plant							
1	LPG Production Plant	DT10	Design Day	28	12	16	0	0
	Storage Plant							
2	LNG Storage	DT20	Design Day	155	69	86	0	0
	Transmission Plant							
3	Transmission Plant	DT30	Average and Peak	241	82	103	11	45
	Distribution Plant							
4	Regulator Stations	DT41	Average and Peak	48	16	20	2	9
5	Mains	FT42	Mains overall	2,582	881	1,102	122	477
6	Services	DT43	Serv Study	1,777	1,325	424	20	7
7	Meters	DT44	Meter Study	686	305	351	20	9
8	House Regulators	DT45	Regut Study	83	53	28	1	1
9	**Total**	**DT40**		5,175	2,581	1,925	165	504
10	**ADIT w/o Gen & Com**	**DT60**		5,599	2,745	2,130	176	549
	General Plant							
11	General Plant	**DT70**	DT60	190	93	72	6	19
	Common Plant							
12	Common Plant	**DT60**	DT60	493	242	188	16	48
	Adjustments							
13	Accum Def Tax - TBT	DTTBT	Net Plant	27	13	10	1	3
14	Non-Plant Related	DTTTD	Labor	-366	-233	-105	-11	-17
15	**Total Inc Tax Lib Depr**	**DT00**		5,943	2,859	2,295	188	601
16	**Total Subtractions**	**ADT**		5,943	2,859	2,295	188	601

Additions to Net Plant (Pg 1 of 2)

	CWIP	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production	CP10	Design Day	38	17	21	0	0
2	LNG Storage Plant	CP20	Design Day	52	23	28	0	0
3	Transmission Plant	CP31	Average and Peak	11	4	5	1	2
4	Distribution Plant Mains	CP42	Mains overall	0	0	0	0	0
5	General Plant Distribution	CP54	Dist Plant	0	0	0	0	0
6	Common Plant Distribution	CP64	Dist Plant	0	0	0	0	0
7	**Total CWIP**	**CWIP**		101	44	55	1	2
	Materials & Supplies							
8	Materials and Supplies	MSP	Trans+Dist	188	92	70	6	19
	Gas In Storage							
9	LPG In Storage	MSGPN	Sales	272	84	106	17	65
10	LNG In Storage	MSGPM	Sales	499	154	194	31	120
11	NatGas Underground	SMGN	Sales	3,063	945	1,189	193	736
12	**Total**	**MSG**		3,834	1,182	1,488	242	922
	Non-Plant Assets & Liab							
13	Pension Liability	NON1	Labor	0	0	0	0	0
14	Accrued Vacation Reserve	NON2	Labor	0	0	0	0	0
15	Early Retirement Amortization	NON3	Labor	0	0	0	0	0
16	SFAS 106	NON4	Labor	0	0	0	0	0
17	SFAS 112	NON5	Labor	0	0	0	0	0
18	Deferred Gas Costs	NON6	Labor	0	0	0	0	0
19	All Other Adjustments	NON7	Labor	-574	-366	-164	-16	-27
13	**Total Non-Plt Assets & Liab**	**NON**		-574	-366	-164	-16	-27

Additions to Net Plant (Pg 2 of 2)

	Miscellaneous	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Prepay Insurance	PPI	Trans+Dist	85	42	32	3	9
2	Prepay Gas Reserv Fee	PPG	Design Day	1,181	527	654	0	0
3	Prepay Miscellaneous	PPM	Trans+Dist	44	22	16	1	4
4	Rate Case Exp Amort	RCAS	Pres Rev, Rev	0	0	0	0	0
5	Inc Tax Defer Inter Amort	ITD		0	0	0	0	0
6	Project 2000 Amortization	P2000		0	0	0	0	0
7	Customer Advances	CAD	Sales	-16	-5	-6	-1	-4
8	Other Working Capital	RCWO	Pres Rev, Rev	1,688	646	757	96	188
9	**Total**	**MISC**		**2,982**	**1,232**	**1,453**	**99**	**198**
	Working Cash							
10	Purchase Gas Exp - Commodity	WC11	Sales	-367	-113	-143	-23	-88
11	Purchase Gas Exp - Demand	WC12	Design Day	-80	-27	-33	0	0
12	Labor - Regular	WC13	Oper & Maint	-7	-3	-3	0	-1
13	Labor - Incentive Compensation	WC14	Oper & Maint	-5	-2	-2	0	-1
14	Pension and Benefits	WC15	Labor	-2	-1	-1	0	0
15	Payroll Taxes	WC16	Labor	-1	0	0	0	0
16	Other Operating Expenses	WC17	Oper & Maint	-17	-6	-7	-1	-2
17	Property Taxes	WC18	Origl Plant	-64	-31	-25	-2	-5
18	Gross Receipts Tax	WC19	Fees, Rev	-13	-5	-6	-1	-1
19	Federal Income Tax	WC20	Rt Bas w/o WC	-2	-1	-1	0	0
20	State Income Tax	WC21	Rt Bas w/o WC	0	0	0	0	0
21	State Sales Tax	WC22	Pres Rev, Rev	-11	-4	-5	-1	-1
22	**Total Working Cash**	**WCASH**		**-549**	**-195**	**-226**	**-28**	**-100**
23	**Total Additions**	**ADDIT**		**5,982**	**1,990**	**2,676**	**303**	**1,013**
24	**Total Rate Base**	**BASE**		**42,398**	**19,753**	**16,640**	**1,454**	**4,552**
25	Customer Component			16,545	10,781	5,370	274	120
26	Capacity Component			21,278	7,539	9,417	880	3,443
27	Commod Component			7,924	1,434	1,856	300	990

Operating Revenue (Cal Month)

	Retail Revenue	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	**Present Retail Rev**	**R01**	**Direct**	**68,841**	**26,361**	**30,885**	**3,912**	**7,683**
2	**Proposed Retail Rev**	**R01P**	**Direct**	**70,116**	**27,577**	**30,886**	**3,939**	**7,713**
3	Gross Reciept taxes	R04	Direct	0	0	0	0	0
4	Proposed Transportation	R05	Net Plant	0	0	0	0	0
5	Interdepart'l - Angus Anson	R06	Design Day	0	0	0	0	0
4	**Total Rate Rev Present**	**R10**		**68,841**	**26,361**	**30,885**	**3,912**	**7,683**
	Other Operating Rev							
8	Late Pay Penalties	R21	Present Revenues	131	50	59	7	15
9	Penalties - Non-Curtailment	R22	Sales	0	0	0	0	0
10	Connection Charges	R23	Customers	45	38	7	0	0
11	Return Check Charges	R24	Customers	2	2	0	0	0
12	Gross Reciept Taxes	R25	Direct	979	403	446	62	67
13	Gas Agreement	R28	Design Day	26	12	14	0	0
14	Locating Services	R29	Dist Expen	0	0	0	0	0
15	Balancing Services	R30	Sales	30	9	12	2	7
16	Ltd Firm Sales - Rsrvs & Vols	R31	Design Day	37	17	20	0	0
17	Standy Sales - Resrvs & Vols	R32	Design Day	0	0	0	0	0
18	LP Sales to Others - MN	R33	Design Day	0	0	0	0	0
19	Off-System Sales	R34	Design Day	0	0	0	0	0
20	Opportunity Sales	R35	Design Day	1,475	658	817	0	0
21	Contr In Aid Cons Tax Gross-Up	R36	CWIP	0	0	0	0	0
22	Other - Miscellaneous	R37	DsnDay+Sales	41	15	19	1	5
23	**Tot Other Op - Present**	**R20**		**2,766**	**1,205**	**1,394**	**73**	**94**
26	**Tot Oper Rev - Present**	**R00**		**71,607**	**27,566**	**32,279**	**3,986**	**7,777**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Commodity	OXPGE	Direct	47,130	16,607	20,834	3,272	6,417
2	Demand	OXPGD	Direct	8,695	3,871	4,824	0	0
3	Other Purchased Gas	OXOPG	Sales	0	0	0	0	0
4	Opportunity Sales	OXOSN	Design Day	1,424	636	788	0	0
5	Limited Firm	OXANG	Design Day	18	8	10	0	0
6	**Total Purchases**	**OXPG**		**57,267**	**21,122**	**26,456**	**3,272**	**6,417**
	Other Production Exp							
7	Gas Agreement - NSP(W)	OXOSA	Design Day	0	0	0	0	0
8	MGP	OXOSSN	Sales	360	111	140	23	87
9	Misc LPG Op Exp	OXLPN	Design Day	143	64	79	0	0
10	Misc LNG Op Exp	OXLPM	DsnDay+Sales	221	83	104	7	27
11	**Total Other Prod Exp**	**OXOP**		**724**	**258**	**323**	**30**	**113**
	Other Transmission Expense							
12	Other Trans Expense	OX30	Average and Peak	96	33	41	5	18
	Distribution Expense							
13	Regulator Stations	OX41	Average and Peak	42	14	18	2	8
14	Mains	OX42	Mains overall	277	95	118	13	51
15	Services	OX43	Serv Study	203	151	48	2	1
16	Meters	OX44	Meter Study	225	100	115	7	3
17	House Regulators	OX45	Regul Study	28	18	9	0	0
18	Other Property & Equip	OX46	Customers	1	1	0	0	0
19	Dispatching	OX47	DsnDay+Sales	86	32	40	3	10
20	Customer Installations	OX48	Customers	392	332	59	1	0
21	Other Distribution	OX49	Customers	240	203	36	1	0
22	Supervision & Engineering	OX50	DisExp w/o Sup	170	108	51	3	8
23	**Total Distribution**	**OX40**		**1,664**	**1,054**	**496**	**32**	**82**

Operation & Maintenance (Pg 2 of 2)

	Customer Accounting	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Customer Billing Exp	OXBE	Customers	1,142	967	172	3	1
2	Customer Accl Exp	OXCA	Customers	58	49	9	0	0
3	Customer Service & Info	OXSI	Customers	22	19	3	0	0
4	**Total**	**OXCASI**		**1,222**	**1,034**	**184**	**3**	**1**
	Admin & General							
5	Property Insurance	OXAGPI	Net Plant	47	23	18	1	5
6	Pension and Benefits - ESOP	OXAGPS	Labor	0	0	0	0	0
7	Pension and Benefits - Direct	OXAGBL	Labor	540	344	155	16	26
8	Incentive Compensation	OXAGB	Labor	99	63	28	3	5
9	Injuries and Claims	OXAGID	Plant+Reven	115	50	48	5	12
10	Regulation Expense	OXAGR	Pres Rev, Rev	17	7	8	1	2
11	Promotional Adv / Contrib Adj	OXADV	Plant+Reven	36	16	15	2	4
12	Direct Assigned	OXDIR	Plant+Reven	191	83	80	8	20
13	Misc Labor Adjustments	OXAGBS	Labor	439	280	126	13	21
14	Non-Regulated Exp Credits	OXCRED	Plant+Reven	-26	-11	-11	-1	-3
15	**Total A & G Expense**	**OXAG**		**1,458**	**854**	**467**	**47**	**91**
	Amortizations							
16	CIP / DSM Amortization	OXCIP	Sales MCF	0	0	0	0	0
17	MN Energy Policy Rider	OXCLN	Sales MCF	0	0	0	0	0
18	Rate Case Exp Amort	RCA	Pres Rev, Rev	20	8	9	1	2
19	Inc Tax Defer Inter Amort	ITDA	Rt Bas w/o WC	0	0	0	0	0
20	Project 2000 Amortization	P2A	Plant+Reven	0	0	0	0	0
21	**Total Amortizations**	**OXC**		**20**	**8**	**9**	**1**	**2**
	Sales Expense							
22	Gross Sales Expense	OXSALX	Sales Exp Study	131	57	10	53	11
23	Sales Expen Exlcusions	OXSEE	Sales Exp Study	0	0	0	0	0
24	Economic Develop @50%	OXSED	DsnDay+Sales	0	0	0	0	0
25	Other Misc - TBT	OXTBT	Net Plant	0	0	0	0	0
26	**Total**	**OXSE**		**131**	**57**	**10**	**53**	**11**
27	**Total O&M Expense**	**OXT**		**62,582**	**24,419**	**27,985**	**3,442**	**6,735**

Book Depreciation

		Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
	Production Plant							
1	LPG Production Plant	DX10	Design Day	37	17	20	0	0
	Storage Plant							
2	LNG Storage	DX20	Design Day	64	29	35	0	0
	Transmission Plant							
6	Transmission Plant	DX30	Average and Peak	95	32	41	4	18
	Distribution Plant							
7	Regulator Stations	DX41	Average and Peak	18	6	8	1	3
8	Mains	DX42	Mains overall	931	318	397	44	172
9	Services	DX43	Serv Study	580	433	138	7	2
10	Meters	DX44	Meter Study	318	141	163	9	4
11	House Regulators	DX45	Regul Study	21	13	7	0	0
12	Lakes Area Surcharge	DX46	Dist Plant	0	0	0	0	0
13	**Total**	**DX40**		**1,867**	**911**	**713**	**61**	**182**
14	**Depreciation Expense w/o Com & Gen**	**DX50**		**2,063**	**988**	**809**	**65**	**200**
	General Plant							
14	General Plant	**DX70**	DX60	**111**	**53**	**44**	**4**	**11**
	Common Plant							
19	Common Plant	**DX80**	DX60	**524**	**251**	**206**	**17**	**51**
24	**Total Book Deprec**	**DX00**		**2,698**	**1,293**	**1,059**	**85**	**262**

Real Estate & Property Taxes

	Production Plant-	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PT10	Design Day	37	16	20	0	0
	Storage Plant							
2	LNG Storage	PT20	Design Day	75	34	42	0	0
	Transmission Plant							
3	Transmission Plant	PT30	Average and Peak	37	13	16	2	7
	Distribution Plant							
4	Regulator Stations	PT41	Average and Peak	8	3	3	0	1
5	Mains	PT42	Mains overall	421	144	180	20	78
6	Services	PT43	Serv Study	290	216	69	3	1
7	Meters	PT44	Meter Study	112	50	57	3	2
8	House Regulators	PT45	Regul Study	13	9	5	0	0
9	Other Prop & Equip	PT46	Dist Plant	0	0	0	0	0
10	**Total**	PT40		844	421	314	27	82
11	Real Est & Prop Taxes w/o Gen & Com	PT60		993	483	392	29	89
	General Plant							
18	General Plant	PT70	PT60	2	1	1	0	0
	Common Plant							
23	Common Plant	PT80	PT60	7	3	3	0	1
24	**Tot RI Est & Pr Tax**	PT0		1,002	488	396	29	90
25	Gross Earnings Tax	GETX	Direct	979	403	446	62	67
26	Payroll Taxes	Z00	Labor	163	104	47	5	8
27	**Tot Non-Income Taxes**	PTOT		2,144	995	888	96	165

Provision For Deferred Income Taxes

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PR10	Design Day	-3	-1	-2	0	0
	Storage Plant							
2	LNG Storage	PR20	Design Day	21	9	12	0	0
	Transmission Plant							
3	Transmission Plant	PR30	Average and Peak	83	28	35	4	15
	Distribution Plant							
4	Regulator Stations	PR41	Average and Peak	5	2	2	0	1
5	Mains	PR42	Mains overall	285	97	122	13	53
6	Services	PR43	Serv Study	196	146	47	2	1
7	Meters	PR44	Meter Study	76	34	39	2	1
8	House Regulators	PR45	Regul Study	9	6	3	0	0
9	Total	PR40		571	285	212	18	56
10	Provision w/o Gen & Com	PR60		672	321	258	22	71
	General Plant							
11	General Plant	PR70	PR60	-19	-9	-7	-1	-2
	Common Plant							
22	Common Plant	PR80	PR60	45	22	17	1	5
	Other							
29	All Other Adjustments	PR77	Labor	-117	-75	-34	-3	-6
	Total Other	PR70		-117	-75	-34	-3	-6
30	Tot Prov For Defer	PR0		581	259	234	20	68

Investment Tax Credit For Current Income

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	CI10	Design Day	0	0	0	0	0
	Storage Plant							
2	LNG Storage	CI20	Design Day	-1	0	-1	0	0
	Transmission Plant							
3	Transmision Plant	CI30	Average and Peak	-2	-1	-1	0	0
	Distribution Plant							
6	Regulator Stations	CI41	Average and Peak	0	0	0	0	0
7	Mains	CI42	Mains overall	-13	-4	-6	-1	-2
8	Services	CI43	Serv Study	-10	-7	-2	0	0
9	Meters	CI44	Meter Study	-4	-2	-2	0	0
10	House Regulators	CI45	Regul Study	0	0	0	0	0
11	**Total**	**CI40**		-27	-14	-10	-1	-3
12	ITC w/o gen and Com	CI60	subtotal	-30	-15	-11	-1	-3
	General Plant							
13	General Plant	CI70	CI60	0	0	0	0	0
	Common Plant							
14	Common Plant	CI80	CI60	0	0	0	0	0
15	**Tot ITC For Curr Inc**	**CI00**		-30	-15	-11	-1	-3
16	**Gross Inv Tax Credit**	**DI5**		0	0	0	0	0
17	**Net Inv Tax Credit**	**DI00**		-30	-15	-11	-1	-3
18	**Total Operating Exp**	**TOE**		67,975	26,951	30,155	3,642	7,227
19	**Op Inc Before Inc Tax**	**OPY**		3,632	614	2,124	343	550

Tax Depreciation & Removal Exp Generated

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	TA10	Design Day	36	16	20	0	0
	Storage Plant							
2	LNG Storage	TA20	Design Day	118	53	65	0	0
	Transmission Plant							
3	Transmission Plant	TA30	Average and Peak	317	108	135	15	59
	Distribution Plant							
7	Regulator Stations	TA41	Average and Peak	34	12	14	2	6
8	Mains	TA42	Mains overall	1,820	621	777	86	337
9	Services	TA43	Serv Study	1,252	934	299	14	5
10	Meters	TA44	Meter Study	483	215	248	14	7
11	House Regulators	TA45	Regul Study	58	37	20	0	1
12	Other Property & Equip	TA46	Dist Plant	0	0	0	0	0
13	**Total**	TA40		3,647	1,819	1,357	116	355
14	**Tax Depreciation w/o Gen & Com**	TA50	Subtotal	4,118	1,995	1,577	131	414
	General Plant							
14	General Plant	TA70	TA60	109	53	42	3	11
	Common Plant							
23	Common Plant	TA80	TA60	562	272	215	18	56
24	Tax Benefit Transfers	TATBT	Net Plant	-125	-61	-48	-4	-12
25	**Total Tax Depreciation**	TA00		4,664	2,260	1,787	149	469

Present Return

	Inc Tax Additions	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Total Book Depr Exp	DX00		2,698	1,293	1,059	85	262
2	Book Dep Cleared To Operating	DX99	Book Deprec	78	37	31	2	8
3	Provision for Deferred	PRO		581	259	234	20	68
4	Net Inv Tax Credit	DI00		-30	-15	-11	-1	-3
5	Book Amortizations	NDDI	Net Plant	20	10	8	1	2
6	Connect Fees and Other	ND2B	Customers	81	69	12	0	0
7	Avoided Tax Interest	ND2ASP	CWIP	106	46	57	1	2
8	Tax Capitalized Leases	NDTC	Plant	0	0	0	0	0
9	Meals & Entertainment	NDME	Labor	3	2	1	0	0
10	TBT Net Expense	NDTBT	Net Plant	0	0	0	0	0
11	**Total Tax Additions**			**3,537**	**1,700**	**1,390**	**108**	**339**
	Inc Tax Deductions							
12	Tax Depr & Removal Exp	TA00		4,664	2,260	1,787	149	469
13	Debt Interest Expense	ND1	Rate Base	1,548	721	608	53	166
14	Other Timing Differerences	PRMPAG	Labor	-75	-48	-21	-2	-4
15	Net Preferred Stock Deduction	OTHLHD	Net Plant	0	0	0	0	0
16	**Total**			**6,137**	**2,933**	**2,373**	**200**	**632**
17	**Taxable Net Income**	FSNI		**1,031**	**-619**	**1,141**	**252**	**257**
18	**Inc Tax (Pre-Credits), @39.55%**	TAX		**408**	**-245**	**451**	**99**	**102**
19	**Tax Credits**			**0**	**0**	**0**	**0**	**0**
20	**Fed & State Inc Tax**	**TAXES**		**408**	**-245**	**451**	**99**	**102**
21	**Total AFUDC**	**AFC**	**CWIP**	**0**	**0**	**0**	**0**	**0**
22	**Pres Return**	**RETR**	**,BASE**	**3,224**	**859**	**1,673**	**244**	**448**
23	**Pres Return on Rate Base**	**RTRT**		**7.60%**	**4.35%**	**10.05%**	**16.76%**	**9.85%**

Labor Allocator

					336,490			
	Labor Components	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
24	Customer Billing	LAB1	Wtd Customer	3.4%	2.8%	0.5%	0.1%	0.0%
25	Customer Accounting	LAB2	Customer	10.8%	9.2%	1.6%	0.0%	0.0%
26	Cust Serv & Inform	LAB3	Customer	2.3%	2.0%	0.3%	0.0%	0.0%
27	Distribution	LAB4	Dist Expen	70.2%	44.5%	20.9%	1.3%	3.5%
28	Gas Storage - LNG	LAB5	DsnDay+Sales	5.4%	2.0%	2.5%	0.2%	0.6%
29	Production	LAB6	Other Produc	2.6%	0.9%	1.1%	0.1%	0.4%
30	Sales	LAB7	Sales Exp Study	2.9%	1.3%	0.2%	1.2%	0.2%
31	Transmission	LAB8	Design Day	2.4%	1.1%	1.4%	0.0%	0.0%
32	**Total**	LABOR		100.0%	63.7%	28.6%	2.9%	4.8%

EXTERNAL ALLOCATORS		ND	Res	Sm C/I	Sm Int	Lg Int
Customer Related						
1 Customers - B Basis	C10	40,827	34,553	6,141	110	23
%1 Customers - B Basis	C10	100 00%	84 63%	15 04%	0 27%	0 06%
2 Service Weighting (index)	C20		1 00	1 80	4 75	8 19
2 Weighted Service	C20	46,318	34,553	11,054	523	188
%2 Services Factor	C20	100 00%	74 60%	23 87%	1 13%	0 41%
3 Meter Factor Weighting (Index)	C21		1 00	6 48	20 47	45 95
3 Weighted Meter	C21	77,659	34,553	39,794	2,255	1,057
%3 Meter Factor	C21	100 00%	44 49%	51 24%	2 90%	1 36%
4 House Regulator Weighting (index)	C22		1 00	2 95	3 79	30 84
4 Weighted Regulator		53,817	34,553	18,138	418	709
%4 House Regulator Factor	C22	100 00%	64.20%	33 70%	0 78%	1 32%
5 Sale expense Weighting	E03		0 000762	0 000762	0 222279	0.222279
5 Weighted Sales Expense	E03	61	26	5	24	5
%5 Sales Expense	E03	100 00%	43 44%	7 72%	40 40%	8 44%
6 Cust Acctg Weights	C10WTS	23	1	1	6	6
6 Weighted Customers	C10W	41,493	34,553	6,141	661	138
%6 Weighted Custs (Cust Acctg)	C10W	100 000%	83 274%	14 800%	1 593%	0 333%
Main Allocator						
Mains - Average Day (Sales)		26,819	8,270	10,411	1,689	6,448
Mains - Average Day (Sales)	Load Factor =	100 00%	30 84%	38 82%	6 30%	24 04%
(Transportation adder)						
Mains - Excess Design Day		56,828	24,971	30,809	0	1,047
Mains - Excess Design Day		100 00%	43 94%	54 22%	0 00%	1 84%
Mains Average and Peak		30,055	10,253	12,824	1,420	5,558
Average and Peak		100 00%	34 11%	42 67%	4 72%	18 49%
Mains overall		30,055	10,253	12,824	1,420	5,558
Mains overall		100.00%	34 11%	42 67%	4 72%	18 49%
Sales and Capacity Related						
6 Design Day	D10	74,462	33,242	41,220	0	0
%6 Design Day %	D10	100 00%	44 64%	55 36%	0 00%	0 00%
7 Sales MCF	E10	9,788,919	3,018,662	3,800,041	616,604	2,353,612
%7 Sales MCF	E10	100 00%	30 84%	38 82%	6 30%	24 04%
8 Sales MCF (Exc CIP exempt)	E10CIP	8,948,819	3,018,662	3,800,041	616,604	1,513,512
%8 Sales MCF	E10CIP	100 00%	33 73%	42 46%	6 89%	16 91%
9 Gross Receipts	GR10	1,068,746	440,304	486,820	68,084	73,558
%9 Gross Receipts	GR10	100 00%	41 20%	45 55%	6 37%	6 88%
%10 CIP Allocator	GR10	3,346	0	0	0	0
CIP Allocator	GR10	0 00%	0 00%	0 00%	0 00%	0 00%
11 LatePayment Revenues	LPY					
%11 LatePayment Revenues	LPY	100 00%	38 29%	44 86%	5 68%	11 16%
12 Present Rev		68,841	26,361	30,885	3,912	7,683
%12 Present Rev	R01	100 00%	38 29%	44 86%	5 68%	11 16%

INTERNAL ALLOCATORS		ND	Res	Sm C/I	Sm Int	Lg Int
1 Rate Base		42,398	19,753	16,640	1,454	4,552
%1 Rate Base	BASE-COL	100 000%	46 589%	39 246%	3 429%	10 736%
			100 000%	100 000%	100 000%	100 000%
2 Rate Base less Working Cash		39,965	18,716	15,412	1,383	4,454
%2 Rate Base less Working Cash	BASEWC	100 000%	46 830%	38 565%	3 460%	11 145%
		101	44	55	1	2
4 Construction Work In Progress	CWIP	100 000%	43 496%	53 976%	0 515%	2 014%
5 50% Design Day, 50% Energy	D10E10	100 000%	37 740%	47 089%	3 149%	12 022%
7 Book Depreciation	DX00	100 000%	47 907%	39 234%	3 163%	9 696%
8 50% Gross Plant, 50% Pres Rev	EGPRV	100 000%	43 525%	41 831%	4 352%	10.291%
9 Gas Plant In Service	GPIS	100 000%	48 758%	38 799%	3 021%	9 423%
9 Gas Plant In Service (w/o Gen and Common)	GPIS (B)	100 000%	48 758%	38 799%	3 021%	9 423%
10 Labor	LABOR	100 000%	63 704%	28 638%	2 873%	4 785%
11 Net Gas Plant In Svc (w/o TBT)	NGPIS(A)	100 000%	48 685%	38 382%	3 162%	9 771%
12 Dis O&M w/o Sup & Misc	OXDTS	1,494	946	445	29	74
12 Dist O&M (w/o Sup & Eng)	OX40(A)	100 000%	63 353%	29 787%	1 910%	4 951%
13 Other Production Expense	OXOP	100 000%	35 671%	44 610%	4 093%	15 625%
14 Oper & Maint Expense	OXT	100 000%	39 020%	44 718%	5 501%	10 762%
15 Distribution Plant	P40	100 000%	49 867%	37 207%	3 186%	9 740%
4 Transmission & Distribution	TD	63,373	31,107	23,751	2,067	6,448
4 Transmission & Distribution	TD	100 000%	49 086%	37 478%	3 262%	10 174%
17 Rev w/o Regul Exp, Col %'s	R02-COL	100 000%	39 829%	43 868%	5 371%	10 933%

CONSTANTS FOR REV CALCULATION

			Rate	Ratio	Wtd Cost
1	Long Term Debt		7.3300%	48 6530%	3 5663%
2	Short Term Debt		7.7400%	1.1070%	0 0857%
3	Debt Total		7 3392%	49 7600%	3 6520%
4	Preferred Stock		0 0000%	0 0000%	0 0000%
5	Common Equity		11.5000%	50 2400%	5 7776%
6	Required Rate of Return			100 0000%	9 4296%
7	MN Combined State & Fed Tax Rate	TAXRATE	0 3955000		
8	1 / (1 - Tax Rate) Factor	ONEOVER	1 6542600		
9	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	0 6542600		

APPROVED
DATE: 4-20-05
KME

MOTION

April 20, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission bill Northern States Power Company for costs incurred to date in Case No. PU-04-578, Northern States Power Company, Natural Gas Rate Increase, Application.

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

April 20, 2005

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

RE: Case No. PU-04-578
Northern States Power Company
Natural Gas Rate Increase
Application

Enclosed is a copy of the statement approved at the April 20, 2005 Public Service Commission meeting for the expenses incurred to date in Case No. PU-04-578

Under N.D C C 49-02-02, these expenses are billed through the Valuation Fund and must be paid for by the company involved.

Please make your check payable to the Public Service Commission.

Sincerely,

Gloria Geiger
Admin Staff Officer
701-328-2401

Enc

c: James P Johnson
Northern States Power Co
800 Nicollet Mall Ste 2900
Minneapolis MN 55401

Billing Statement

April 20, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

Expenses Incurred to Date:

Larkin & Associates	$12,760.00
Advertising Costs	640.35
Videoconferencing	238.40
Office of Administrative Hearings	36 37
TOTAL	$13,675.12

Amount Due:

Northern States Power Company $13,675.12

Send Payment and a Copy of this Statement To:

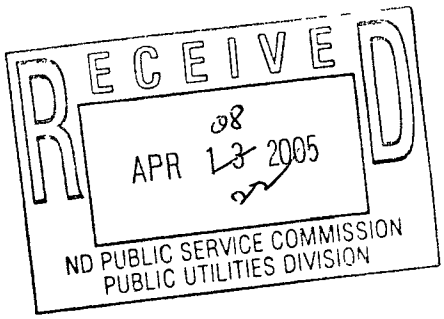
Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck ND 58505-0480

Federal Tax ID 45-0309764

Xcel Energy™

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

April 8, 2005



Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Northern States Power Company d/b/a Xcel Energy
Reconnection Fee for Seasonal or Temporary Customers

Dear Ms. Jeffcoat-Sacco:

In the Settlement Agreement reached between Xcel Energy and the Commission advocacy Staff pertaining to the Company's Natural Gas general rate increase application (Case No. PU-400-04-578), the parties agreed that tariffs should be developed to properly recover the costs of service disconnect and reconnect requests.

Enclosed herein is an original and seven copies (both regular and red-line versions) of a revised Sheet 3, Section 6 of Xcel Energy's North Dakota Gas Rate Book establishing a fee for requests to temporarily disconnect, then reconnect natural gas services. Such requests typically come from customers who are attempting to avoid minimum charges for access to the distribution system during months they are able to forego gas usage. This practice results in other customers subsidizing their natural gas delivery costs, and the ongoing shut-off and turn-on requests add service costs that are not presently being recovered from the very customers who cause them.

These tariff changes are similar to charges recently approved by the Commission for MDU. Xcel Energy also has similar fees in place in its Wisconsin gas service territory.

Please contact me if you have any questions or comments.

Sincerely,

David H. Sederquist

David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Co. d/b/a Xcel Energy

78 PU-04-578 Pages 3

Reconnection fee for seasonal or temporary customers
by Northern States Power Company by

04/08/2005 C Comm Legal PUD (4) Mike ALJ

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO. 2

GENERAL RULES AND REGULATIONS (Continued)

Section No 6
1st Revised Sheet No 3

SECTION 1 GENERAL SERVICE RULES

1.1 APPLICATION FOR SERVICE

A party desiring gas service must make application to the Company before commencing the use of the Company's service The Company reserves the right to require a signed application or written contract for service to be furnished All applications and contracts for service must be made in the legal name of the party desiring the service The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish reasonable information requested by the Company for the establishment of a service account Any person who uses gas service in the absence of application or contract shall be subject to the Company's rates, rules, and regulations and shall be responsible for payment of all service used

When required by governmental authority, a customer desiring new service or expanded service first must make application for and receive written approval from the Company

Subject to its rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service The customer will be responsible for payment of all service furnished through the date of discontinuance

1.2 SERVICE PROCESSING CHARGE

The Company will charge $15 00 for the initial establishment or the reestablishment of service for each customer If any combination of gas or electric services requested by a customer and furnished by the Company is established or reestablished at the same time and location, only one $15 00 charge will be made N N

If a customer requests reestablishment of service at a location where the same customer discontinued the same service within the preceding 12 month period, an additional reconnection fee will be assessed equal to the sum of the monthly minimum charges applicable during the period service was not taken N | N

1.3 ACCESS TO CUSTOMER'S PREMISES

Company representatives, when properly identified, shall have access to customer's premises at all reasonable times for the purpose of reading meters, making repairs, making inspections, removing the Company's property, or for any other purpose incident to the service

1.4 CONTINUITY OF SERVICE

The Company will use all reasonable care to provide continuous service but does not assume responsibility for a regular and uninterrupted supply of gas service and will not be liable for any loss, injury, or damage resulting from the use of service, or arising from or caused by the interruption or curtailment of the same

(Continued on Sheet No 6-4)

Northern States Power Company
Minneapolis, Minnesota 55401
NORTH DAKOTA GAS RATE BOOK - NDPSC NO. 2

GENERAL RULES AND REGULATIONS (Continued)

Section No 6
~~Original~~ 1st Revised Sheet No 3
~~Relocated from NDPSC No 1 Sheet No G-24~~

SECTION 1 GENERAL SERVICE RULES

1 1 APPLICATION FOR SERVICE

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When required by governmental authority, a customer desiring new service or expanded service first must make application for and receive written approval from the Company

Subject to its rates, rules, and regulations, the Company will continue to supply gas service until notified by customer to discontinue the service The customer will be responsible for payment of all service furnished through the date of discontinuance

1.2 SERVICE PROCESSING CHARGE

The Company will charge ~~$12~~15 00 for the initial establishment or the reestablishment of service for each customer If any combination of gas or electric services requested by a customer and furnished by the Company is established or reestablished at the same time and location, only one ~~$12~~15 00 charge will be made N N

If a customer requests reestablishment of service at a location where the same customer discontinued the same service within the preceding 12 month period, an additional reconnection fee will be assessed equal to the sum of the monthly minimum charges applicable during the period service was not taken N N

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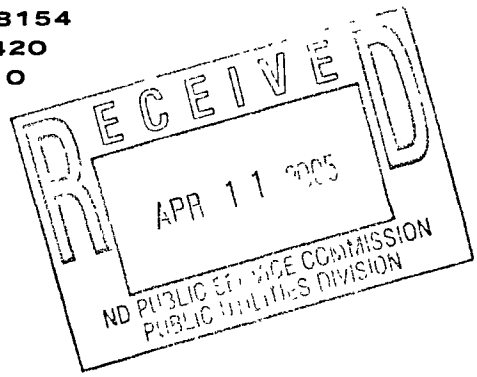
1 4 CONTINUITY OF SERVICE

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(Continued on Sheet No 6-4)

LARKIN & ASSOCIATES, PLLC

CERTIFIED PUBLIC ACCOUNTANTS
15728 FARMINGTON ROAD
LIVONIA, MICHIGAN 48154
PHONE (734) 522-3420
FAX (734) 522-1410



April 6, 2005

Mr. Jerry Lein
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

NSP-ND Gas Cost of Capital, Case No. PU-04-578
Billing for Professional Services Rendered through April 3, 2005.

	Hours		Hourly Rate	Total Amount
Hugh Larkin, Jr.	0.0	@	$ 125.00	$ -
Helmuth W. Schultz	0.0	@	$ 115.00	$ -
Aaron Rothschild	0.0	@	$ 85.00	$ -
Ralph C. Smith	1.5	@	$ 115.00	$ 172.50
Donna M. DeRonne	0.0	@	$ 115.00	$ -
Christine Miller	0.0	@	$ 65.00	$ -
Mark S. Dady	0.0	@	$ 65.00	$ -
Word Processing/Clerical	0.0	@	$ 20.00	$ -
Total Professional	1.5			$ 172.50
Expenses (See attached detail)				$ 28.37
Total Amount				$ 200.87

OK
WCK
4-11-05

77 PU-04-578 Pages 3

Billing for professional services rendered through April 3, 2005 by Larkin & Associates Pllc

04/11/2005 C Comm Legal PUD (4) Mike

NSP-ND Gas

March 2005 Summary (02/28/05 - 04/03/05)

Name	Date	Client	Company	Work Description	Hours	Expenses
R Smith	02/28/05	ND PSC	NSP-ND Gas	Discuss schedule with Staff, forward emailed documents to Aaron Rothschild	0.5	
R Smith	03/01/05	ND PSC	NSP-ND Gas	Receive & forward bulk DR responses to Aaron Rothschild	0.5	
R Smith	03/02/05	ND PSC	NSP-ND Gas	Project supervision	0.5	
				Total Hours	1.5	

Expenses -

Expense	March-05	ND PSC	NSP-ND Gas	Fed Ex Monthly Shipping Bill		$ 28 37
				Total Amount		$ 28 37

FedEx Billing Online Plus

FedEx Billing Online Plus

Express Tracking ID Detail

Tracking ID Summary

Tracking ID Number :	845512146308
Invoice Number .	5-409-82905
Primary Account :	1081-8298-9
Invoice Date :	03/09/2005
Due Date :	03/24/2005
Tracking ID Balance Due :	$ 28 37
Invoice Status :	Open

Package sent from 48174 zip
Distance Based Pricing, Zone 4
Fuel Surcharge - FedEx has applied

North Dakota

Sender Information

ralph smith
LARKIN & ASSOCIATES

15728 FARMINGTON RD
LIVONIA MI 48154-2858
USA

Recipient Information

AARON ROTHSCHILD

500 RIVERSIDE DR

NEW YORK CITY , NY 10027
US

Original Reference

Customer Reference# ND
Department#

Updated Reference

Customer Reference#
Department#

Shipment Details

Shipment Date	03/01/2005
Payment Type	Shipper
Service Type	FedEx Standard Overnight
Region Code	4
Package Type	FedEx Pak
Pieces	1
Actual Weight	8 0 lbs
Bundle ID	0
Meter No	

Charges

Transportation Charge	38 25
Discount	-11 86
Fuel Surcharge	1.98
Weekday Delivery	0 00
Total Charges	USD $ 28.37

Proof of Delivery

Delivery Date	03/02/2005 09 38
Service Area Code	A2
Signed By	A FATIAUA

☐ Non Public Document - Contains Trade Secret Data
☐ Public Document - Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: PU-400-04-578
Response To: Commissioner S. E. Information Request 3-02
Date Received: 3/8/05

Question:

Has the Company been able to recover any of the costs of the Grand Forks manufactured gas plant clean-up project through legal actions?

Response:

No Northern States Power Company d/b/a Xcel Energy has not filed any legal claims in the Grand Forks manufactured gas plant (MGP) clean-up project and has not been able to recover any of the clean-up costs from insurance carriers.

Xcel Energy Services Inc. engaged an outside law firm to evaluate whether the Company's possible claims against its insurance carriers have merit. The Company and its counsel assessed the costs and resources required to file and prosecute insurance recovery claims (including litigation costs) for the Grand Forks clean-up project, as well as the likelihood of success on the merits, compared to the potential benefits in terms of recoveries. The Company determined that the uncertainty, cost, and time required to pursue insurance proceeds is too great at this time

---

Response By: Jim Altman
Title: Assistant General Counsel
Department: Deputy General Counsel
Telephone: 612-215-4582
Date: 3/24/05

☐ Non Public Document - Contains Trade Secret Data
☐ Public Document - Trade Secret Data Excised
☒ Public Document

Xcel Energy
Docket No.: PU-400-04-578
Response To: Commissioner S. E. Information Request 3-01
Date Received: 3/8/05

Question:

Please describe the impact of the Company's Incentive Compensation in this rate case.

Response:

In Case No. PU-400-04-578, Xcel Energy included the costs of base compensation plus a portion of annual incentive compensation in its natural gas rate application. Specifically, Xcel Energy requested that 100 percent of base pay and the target annual incentive compensation level, up to 25 percent of an employee's base salary, be included in the test year revenue requirement

Xcel Energy did not request that any portion of long-term incentive compensation be recovered in rates

The 2004 test year levels of costs for each component of compensation for the North Dakota natural gas jurisdiction are.

Base compensation·	$2,633,279
Incentive compensation (within the 25% cap):	$ 97,943
Incentive compensation excluded from test year	$ 61,420

Xcel Energy provides market competitive compensation through the use of base salaries and annual incentive compensation. The Annual Incentive Plan covers the majority of employees across all states and operating companies, including NSP, with the exception of certain bargaining unit (union) employees. Performance goals are set at the Individual, Business Unit, and Corporate (Xcel Energy Inc.) levels. The weightings assigned to the various components are determined by position level with non-supervisory positions weighted more heavily on individual and business unit performance and executive positions more heavily weighted towards corporate goals The following chart illustrates 2004 target awards (as a percentage of base salary) and program weights:

		Weights		
2004 Salary Tiers/Grades	**Target Award**	**Individual**	**Business Unit**	**Corporate**
Non-exempt, Exempt M-R	6%, 10%, 15%	40%	40%	20%
Management S-V	15%, 20%	20%	50%	30%
Managing Director / Business Unit Vice President	25%, 35%	0%	60%	40%
Corporate Vice President	40%	0%	50%	50%
Business Unit President	55%	0%	33%	67%
President & COO	65%	0%	0%	100%
Chairman & CEO	85%	0%	0%	100%

Xcel Energy's proposal balances the interests of ratepayers and shareholders and protects ratepayers from bearing the financial risks of its incentive compensation programs. This balancing is achieved through: 1) utilizing a prevalent market tool of annual incentive which has become a necessary cost of doing business; 2) our exclusion of all long-term incentive payments; 3) a properly designed annual incentive plan under which customer interests are well represented; and 4) the proposed 25 percent cap on target annual incentive compensation.

Response By: Jeffrey C. Robinson
Title: Manager, Revenue Analysis
Department: Revenue Analysis
Telephone: 612-330-5912
Date: 3/23/05

Fahn, Patrick J.

From: Paluck, Nicholas N [Nicholas N Paluck@xcelenergy com]
Sent: Thursday, March 24, 2005 10 24 AM
To: Fahn, Patrick J
Cc: Darnell, Ron, Sederquist, Dave
Subject: Class Cost of Service Study (CCOSS)

Attachments: GAS_CCOSS_ND_TY2004_Final_toNDPSCforSettlement XLS



GAS_CCOSS_N
Y2004_Final_tol

Mr Fahn,

Attached is the electronic version of the cost of service study that you requested. You will notice that the version attached will look slightly different than the one you received in our initial filing for a couple of reasons First, as you requested, I have broken out cost into "customer related" and "other" costs I have done so for the total ND costs and residential costs Second, the page layout is slightly different and there may be some slight formatting changes made to incorporate the additional columns.

If you have any questions on the CCOSS model or need any assistance with its operation, please do not hesitate to contact me

Sincerely,

Nick Paluck
Pricing & Planning
Xcel Energy Services
612 330 1913
612 330 7601 fx

<<GAS_CCOSS_ND_TY2004_Final_toNDPSCforSettlement XLS>>

Summary: Functionalized Rate Base

	Plant In Service	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Production	P10		0	1,660	0	741	1,660	741	919	0	0
2	Storage	P20		0	3,396	0	1,516	3,396	1,516	1,880	0	0
3	Transmission	P30		0	3,142	0	1,232	3,142	1,232	1,529	71	309
4	Distribution	P40		50,446	9,785	34,387	6,670	60,231	41,057	17,243	751	1,180
5	Sub-total	P60		50,446	17,983	32,840	11,707	68,429	44,547	21,571	822	1,489
6	General	P70		1,235	440	804	287	1,675	1,090	528	20	36
7	Common	P80		3,638	1,297	2,368	844	4,935	3,213	1,556	59	107
8	TBT Investment	PTBT		2	0	1	0	2	1	1	0	0
9	**Total**	PLANT		55,320	19,721	36,013	12,838	**75,041**	**48,851**	**23,656**	**901**	**1,633**
	Depreciation Reserve											
10	Production	A10		0	1,213	0	542	1,213	542	671	0	0
11	Storage	A20		0	2,439	0	1,089	2,439	1,089	1,350	0	0
12	Transmission	A30		0	1,721	0	675	1,721	675	838	39	169
13	Distribution	A40		19,971	3,774	13,750	2,598	23,745	16,348	6,657	287	453
14	Sub-total	A60		19,971	9,147	12,794	5,860	29,118	18,654	9,516	326	623
15	General	A70		665	304	426	195	969	621	317	11	21
16	Common	A80		1,780	815	1,140	522	2,595	1,662	848	29	55
17	**Total**	DEPR		22,416	10,266	14,360	6,577	**32,682**	**20,937**	**10,681**	**366**	**699**
18	**Net Plant With TBT**	NGPIS		32,905	9,454	21,684	6,230	42,359	27,914	12,975	536	934
	Accumulated Deferred Taxes	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
19	Production	DT10		0	28	0	12	28	12	16	0	0
20	Storage	DT20		0	155	0	69	155	69	86	0	0
21	Transmission	DT30		0	241	0	95	241	95	117	5	24
22	Distribution	DT40		4,334	841	2,955	573	5,175	3,528	1,482	65	101
23	Sub-total	DT60		4,334	1,265	2,867	837	5,599	3,704	1,700	70	125
24	General	DT70		147	43	97	28	190	126	58	2	4
25	Common	DT80		382	111	252	74	493	326	150	6	11
26	Non-Plant related	DT90		-260	-79	-179	-54	-339	-233	-89	-8	-9
27	**Total**	ADT		4,603	1,340	3,038	884	5,943	3,922	1,819	70	131
	Construction Work in Progress	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
17	Production	CP10		0	38	0	17	38	17	21	0	0
18	Storage	CP20		0	52	0	23	52	23	29	0	0
19	Transmission	CP31		0	11	0	4	11	4	5	0	1
20	Distribution	CP42		0	0	0	0	0	0	0	0	0
21	Sub-total	CP60		0	101	0	44	101	44	55	0	1
21	General	CP54		0	0	0	0	0	0	0	0	0
22	Common	CP64		0	0	0	0	0	0	0	0	0
23	Non-Plant related	CP90		0	0	0	0	0	0	0	0	0
24	**Total**	CWIP		0	101	0	44	101	44	55	0	1
	Net Investment Rate Base	**Input**	**Alloc**	**Total ND Cust**	**Total ND Other**	**Res Cust**	**Res Other**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
25	Production	NIRB10		0	457	0	204	457	204	253	0	0
26	Storage	NIRB20		0	854	0	381	854	381	473	0	0
27	Transmission	NIRB30		0	1,191	0	467	1,191	467	580	27	117
28	Distribution	NIRB40		26,141	5,170	17,684	3,498	31,311	21,181	9,105	399	625
29	Sub-total	NIRB60		26,141	7,672	17,189	5,045	33,813	22,234	10,410	426	742
30	General	NIRB70		423	93	282	62	516	344	154	7	11
31	Common	NIRB80		1,477	370	979	245	1,847	1,224	558	24	41
32	TBT Investment			2	0	1	0	2	1	1	0	0
33	Non-Plant related	NIRB90		260	79	179	54	339	233	89	8	9
34	**Total**	NIRB		28,302	8,215	18,629	5,408	36,517	24,036	11,211	466	804
	Additions											
35	Materials & Supplies	MSP		150	38	100	26	188	125	56	2	4
36	Gas in Storage	MSG		0	3,834	0	1,182	3,834	1,182	1,488	242	922
37	Non Plant Asset & Liabilities	NON		-440	-134	-302	-92	-574	-394	-152	-13	-15
38	Prepaids and Other	MISC		325	2,657	138	1,124	2,982	1,262	1,449	95	177
39	Cash Working Capital	WCASH		-54	-495	-20	-186	-549	-206	-221	-27	-95
40	**Total**			-20	5,901	-7	1,976	**5,881**	**1,970**	**2,620**	**299**	**993**
41	**Rate Base**	**BASE**		28,282	14,116	17,347	8,658	**42,398**	**26,006**	**13,831**	**764**	**1,797**

Summary, Income Statement

	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
Operating Revenues									
Retail	8,262	60,579	3,197	23,440	68,841	26,637	31,114	3,845	7,245
Other Operating	47	2,719	20	1,185	2,766	1,205	1,395	73	93
Total Operating Revenues	8,309	63,298	3,231	24,612	**71,607**	**27,842**	**32,509**	**3,918**	**7,338**
Expenses									
Operating Expenses									
Purchased Gas (PGA)	0	55,825	0	20,478	55,825	20,478	25,658	3,272	6,417
Purchased Gas other	0	1,442	0	644	1,442	644	798	0	0
Production	0	724	0	258	724	258	323	30	113
Transmission	0	96	0	38	96	38	47	2	9
Distribution	1,427	237	1,003	167	1,664	1,169	445	19	31
Customer Accounting	1,200	0	1,015	0	1,200	1,015	180	3	1
Customer Service and Information	22	0	19	0	22	19	3	0	0
Administrative and General	866	592	559	382	1,458	941	429	37	51
Amortizations	3	17	1	7	20	8	9	1	2
Sales, Econ Develop & Other	0	131	0	57	131	57	10	53	11
Total O&Ms	3,517	59,065	1,384	23,243	**62,582**	**24,627**	**27,903**	**3,417**	**6,635**
Depreciation Expense	2,044	654	1,323	423	2,698	1,745	857	35	61
Taxes other than Income Taxes	839	327	545	212	1,165	758	368	15	25
Deffrred incomes Taxes and ITC	384	167	242	105	551	347	182	6	16
Gross Earnings	0	979	0	403	979	403	446	62	67
Op Income before taxes	1,524	2,107	-16	-22	3,632	(38)	2,753	382	534
State and Federal Income Taxes	-126	534	208	-879	408	(671)	773	134	172
Total Expense	6,658	61,725	2,649	24,560	**68,383**	**27,209**	**30,528**	**3,670**	**6,976**
AFUDC	0	0	0	0	-	-	-	-	-
Total Operating Income	1,651	1,573	324	309	**3,224**	**633**	**1,980**	**248**	**362**
Rate Base	28,282	14,116	17,347	8,658	**42,398**	**26,006**	**13,831**	**764**	**1,797**
Return on Rate Base	0	0	0	0	**7 603%**	**2 435%**	**14 319%**	**32.427%**	**20.158%**
Return on Equity at present rates	0	0	0	0	**7.865%**	**-2 423%**	**21 232%**	**57.275%**	**32 854%**
Required Rate of Return on Rate Base	0	0	0	0	**9 430%**	**9 430%**	**9 430%**	**9 430%**	**9 430%**
Required Operating Income	2,667	1,331	1,636	816	**3,998**	**2,452**	**1,304**	**72**	**169**
Income Deficiency	1,016	-242	2,388	-569	**774**	**1,819**	**-676**	**-176**	**-193**
Revenue Deficiency	1,681	-400	3,950	-941	**1,280**	**3,009**	**-1,119**	**-291**	**-319**
Percent increase indicated	0	0	1	-1	**1.8%**	**10 8%**	**-3 4%**	**-7.4%**	**-4 3%**

Equal Rate of Return

	Total Retail Rev Reqt	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Return On Rate Base			9 43%	0	0	0	9 43%	9 43%	9 43%	9 43%	9 43%
2	Equalized Retail Revenue			9,990	60,132	4,223	25,423	70,122	29,646	29,995	3,554	6,926
3	Present Retail Revenue			8,262	60,579	3,197	23,440	68,841	26,637	31,114	3,845	7,245
4	Revenue Deficiency			1,728	-447	4,060	-1,051	1,281	3,009	-1,119	-291	-319
5	Deficiency / Pres Rev			20 92%	-19 05%	127 00%	-4 48%	1 86%	11 30%	-3 60%	-7 56%	-4 40%
	Internal Rev Reqt											
6	Customer Rev Reqt			9,943	0	7,460	0	9,943	7,460	2,350	94	38
7	Ave Monthly Customers			40,827	0	34,553	0	40,827	34,553	6,141	110	23
8	Rev Reqt $ / Mo / Cust			20 29	0	17 99	0	20 29	17 99	31 89	71 30	138 47
9	Capacity Rev Reqt			0	3,212	0	1,331	3,212	1,331	1,652	43	186
10	Annual MCF Sales			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
11	Rev Reqt $ / MCF (MCF per Month)			0	0	0	0	0 33	0 44	0 43	0 07	0 08
	Capacity - Sub Classification											
12	Capacity -Base Rev Reqt			0	715	0	225	715	225	283	43	164
13	Annual MCF Sales			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
14	Rev Reqt $ / MCF			0	0			0 07	0 07	0 07	0 07	0 07
					0							
15	Capacity -Seasonal Rev Reqt			0	1,213	0	533	1,213	533	658	0	22
16	Annual MCF Sales			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
17	Rev Reqt $ / MCF			0	0	0	0	0 12	0 18	0 17	0 00	0 01
					0							
18	Peak Shaving Rev Reqt			0	1,285	0	573	1,285	573	711	0	0
19	Ave Monthly Customers/ (Design Day)			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
20	Rev Reqt $ / MCF			0	0	0	0	0 13	0 19	0 19	0 00	0 00
12	Energy Rev Reqt			0	1,142	0	377	1,142	377	336	145	284
10	Annual MCF Sales			0	9,788,919	0	3,018,662	9,788,919	3,018,662	3,800,041	616,604	2,353,612
13	Rev Reqt $ / MCF			0	0 12	0	0	0 12	0 12	0 09	0 24	0 12
14	Total Internal Rev Reqt			9,943	4,354	7,460	1,708	14,297	9,168	4,337	282	509
15	Rev Reqt $ / MCF			1 02	0 44	2 47	0 57	1 46	3 04	1 14	0 46	0 22
	External Rev Reqt											
16	Capacity Rev Reqt			0	8,695	0	3,871	8,695	3,871	4,824	0	0
17	Rev Reqt $ / MCF			0 00	0 89	0 00	1 28	0 89	1 28	1 27	0 00	0 00
18	Energy Rev Reqt			0	47,130	0	16,607	47,130	16,607	20,834	3,272	6,417
19	Rev Reqt $ / MCF			0 00	4 81	0 00	5 50	4 81	5 50	5 48	5 31	2 73
20	Total External Rev Reqt			0	55,825	0	20,478	55,825	20,478	25,658	3,272	6,417
21	Rev Reqt $ / MCF			0 00	5 70	0 00	6 78	5 70	6 78	6 75	5 31	2 73
	Total Rev Reqt											
22	Cust Rev Reqt $ / MCF			1 02	0 00	2 47	0 00	1 02	2 47	0 62	0 15	0 02
23	Demd Rev Reqt $ / MCF			0 00	1 22	0 00	1 72	1 22	1 72	1 70	0 07	0 08
24	Ener Rev Reqt $ / MCF			0 00	4 93	0 00	5 63	4 93	5 63	5 57	5 54	2 85
25	Total Rev Reqt $ / MCF			1 02	6 15	1 39	8 43	7 16	9 82	7 89	5 76	2 94
26	Equalized Total Revenue			9,990	62,898	4,228	26,623	72,888	30,851	31,390	3,627	7,019
27	Present Total Revenue			8,309	63,298	3,231	24,612	71,607	27,842	32,509	3,918	7,338
28	Revenue Deficiency			1,681	-400	3,949	-940	1,281	3,009	-1,119	-291	-319
29	Deficiency / Pres Rev			20 23%	-18 44%	122 25%	-111 44%	1 79%	10 81%	-3 44%	-7 42%	-4 35%

Plant in Service

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	P10	Design Day	0	1,660	0	741	**1,660**	741	919	0	0
	Storage Plant											
2	LNG Storage	P20	Design Day	0	3,396	0	1,516	**3,396**	1,516	1,880	0	0
	Transmission Plant											
3	Transmission Plant	P30	Average and Peak	0	3,142	0	1,232	**3,142**	1,232	1,529	71	309
	Distribution Plant											
4	Regulator Stations	P41	Average and Peak	0	558	0	219	558	219	272	13	55
	Mains - Minimum System	P42A	Customers	20,828	0	17,627	0	20,828	17,627	3,133	56	12
5	Mains - Average Capacity	P42B	Average Day (Sales)	0	3,323	0	1,025	3,323	1,025	1,290	209	799
6	Mains - Excess Capacity	P42C	Excess Design Day	0	5,904	0	2,594	5,904	2,594	3,201	0	109
7	Mains - Total	P42		20,828	9,227	14,724	6,523	30,055	21,246	7,624	266	920
8	Services	P43	Serv Study	20,674	0	15,423	0	20,674	15,423	4,934	233	84
9	Meters	P44	Meter Study	7,981	0	3,551	0	7,981	3,551	4,089	232	109
10	House Regulators	P45	Regul Study	963	0	618	0	963	618	325	7	13
11	**Total**	**P40**		50,446	9,785	34,387	6,670	**60,231**	**41,057**	**17,243**	**751**	**1,180**
12	**Plant in Service w/o Gen and Com**	**P60**						**68,429**	**44,547**	**21,571**	**822**	**1,489**
	General Plant											
13	General Plant	**P70**	P60	1,235	440	804	287	**1,675**	**1,090**	**528**	**20**	**36**
	Common Plant											
14	Common Plant	**P80**	P60	3,638	1,297	2,368	844	**4,935**	**3,213**	**1,556**	**59**	**107**
15	Prelim Gas Plant	GPISA		55,319	19,720	36,012	12,838	75,039	48,850	23,655	901	1,633
16	TBT Investment	PTBT	Net Plant	2	0	1	0	2	1	1	0	0
17	**Gas Plant in Serv**	**GPIS**		55,320	19,721	36,013	12,838	**75,041**	**48,851**	**23,656**	**901**	**1,633**

Accumulated Depreciation Reserve

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	A10	Design Day	0	1,213	0	542	1,213	542	671	0	0
	Storage Plant											
2	LNG Storage	A20	Design Day	0	2,439	0	1,089	2,439	1,089	1,350	0	0
	Transmission Plant											
3	Transmission Plant	A30	Average and Peak	0	1,721	0	675	1,721	675	838	39	169
	Distribution Plant											
4	Regulator Stations	A41	Average and Peak	0	136	0	53	136	53	66	3	13
5	Mains	A42	Mains overall	8,211	3,638	5,805	2,572	11,849	8,376	3,006	105	363
6	Services	A43	Serv Study	8,646	0	6,450	0	8,646	6,450	2,063	98	35
7	Meters	A44	Meter Study	2,691	0	1,197	0	2,691	1,197	1,379	78	37
8	House Regulators	A45	Regul Study	423	0	271	0	423	271	143	3	6
9	**Total**	A40		19,971	3,774	13,750	2,598	**23,745**	**16,348**	**6,657**	**287**	**453**
10	**Accum Depr w/o Gen and Com**	A60		19,971	9,147	12,794	5,860	**29,118**	**18,654**	**9,516**	**326**	**623**
	General Plant											
11	General Plant	A70	A60	665	304	426	195	**969**	**621**	**317**	**11**	**21**
	Common Plant											
12	Common Plant	A80	A60	1,780	815	1,140	522	**2,595**	**1,662**	**848**	**29**	**55**
13	**Total Accum Depr**	**APD**		22,416	10,266	14,360	6,577	**32,682**	**20,937**	**10,681**	**366**	**699**
14	**Net Gas Plant Before TBT**	**NGPISA**		32,903	9,454	21,683	6,230	**42,357**	**27,913**	**12,974**	**536**	**934**
15	**Net Plant With TBT**	**NGPIS**		32,905	9,454	21,684	6,230	**42,359**	**27,914**	**12,975**	**536**	**934**

Subtractions to Net Plant (Page 1 of 1)

	Accum Defer Inc Tax Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	DT10	Design Day	0	28	0	12	28	12	16	0	0
	Storage Plant											
2	LNG Storage	DT20	Design Day	0	155	0	69	155	69	86	0	0
	Transmission Plant											
3	Transmission Plant	DT30	Average and Peak	0	241	0	95	**241**	95	117	5	24
	Distribution Plant											
4	Regulator Stations	DT41	Average and Peak	0	48	0	19	48	19	23	1	5
5	Mains	FT42	Mains overall	1,789	793	1,265	560	2,582	1,825	655	23	79
6	Services	DT43	Serv Study	1,777	0	1,325	0	1 777	1,325	424	20	7
7	Meters	DT44	Meter Study	686	0	305	0	686	305	351	20	9
8	House Regulators	DT45	Regul Study	83	0	53	0	83	53	28	1	1
9	**Total**	**DT40**		4,334	841	2,955	573	**5,175**	**3,528**	**1,482**	**65**	**101**
10	**ADIT w/o Gen & Com**	**DT60**				0	3,704	**5,599**	**3,704**	**1,700**	**70**	**125**
	General Plant											
11	General Plant	**DT70**	DT60	147	43	97	28	**190**	**126**	**58**	**2**	**4**
	Common Plant											
12	Common Plant	**DT80**	DT60	382	111	252	74	**493**	**326**	**150**	**6**	**11**
	Adjustments											
13	Accum Def Tax - TBT	**DTTBT**	Net Plant	21	6	14	4	27	17	8	0	1
14	Non-Plant Related	**DTTTD**	Labor	(280)	-85	-192	-58	-366	-251	-97	-8	-10
15	**Total Inc Tax Lib Depr**	**DT00**		4,603	1,340	3,038	884	**5,943**	**3,922**	**1,819**	**70**	**131**
16	**Total Subtractions**	**ADT**		4,603	1,340	3,038	884	**5,943**	**3,922**	**1,819**	**70**	**131**

Additions to Net Plant (Pg 1 of 2)

	CWIP	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production	CP10	Design Day	0	38	0	17	38	17	21	0	0
2	LNG Storage Plant	CP20	Design Day	0	52	0	23	52	23	29	0	0
3	Transmission Plant	CP31	Average and Peak	0	11	0	4	11	4	5	0	1
4	Distribution Plant Mains	CP42	Mains overall	0	0	0	0	0	0	0	0	0
5	General Plant Distribution	CP54	Dist Plant	0	0	0	0	0	0	0	0	0
6	Common Plant, Distribution	CP64	Dist Plant	0	0	0	0	0	0	0	0	0
7	**Total CWIP**	**CWIP**		0	101	0	44	**101**	**44**	**55**	**0**	**1**
	Materials & Supplies											
8	Materials and Supplies	MSP	Trans+Dist	150	38	100	26	188	125	56	2	4
	Gas In Storage											
9	LPG In Storage	MSGPN	Sales	0	272	0	84	272	84	106	17	65
10	LNG In Storage	MSGPM	Sales	0	499	0	154	499	154	194	31	120
11	NatGas Underground	SMGN	Sales	0	3,063	0	945	3,063	945	1,189	193	736
12	**Total**	**MSG**				0	1,182	**3,834**	**1,182**	**1,488**	**242**	**922**
	Non-Plant Assets & Liab											
13	Pension Liability	NON1	Labor	0	0	0	0	0	0	0	0	0
14	Accrued Vacation Reserve	NON2	Labor	0	0	0	0	0	0	0	0	0
15	Early Retirement Amortization	NON3	Labor	0	0	0	0	0	0	0	0	0
16	SFAS 106	NON4	Labor	0	0	0	0	0	0	0	0	0
17	SFAS 112	NON5	Labor	0	0	0	0	0	0	0	0	0
18	Deferred Gas Costs	NON6	Labor	0	0	0	0	0	0	0	0	0
19	All Other Adjustments	NON7	Labor	(440)	-134	-302	-92	-574	-394	-152	-13	-15
13	**Total Non-Plt Assets & Liab**	**NON**		(440)	-134	-302	-92	**-574**	**-394**	**-152**	**-13**	**-15**

Additions to Net Plant (Pg 2 of 2)

	Miscellaneous	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Prepay Insurance	PPI	Trans+Dist	68	17	45	12	85	57	25	1	2
2	Prepay Gas Reserv Fee	PPG	Design Day	0	1,181	0	527	1,181	527	654	0	0
3	Prepay Miscellaneous	PPM	Trans+Dist	35	9	23	6	44	29	13	1	1
4	Rate Case Exp Amort	RCAS	Pres Rev, Rev	0	0	0	0	0	0	0	0	0
5	Inc Tax Defer Inter Amort	ITD		0	0	0	0	0	0	0	0	0
6	Project 2000 Amortization	P2000		0	0	0	0	0	0	0	0	0
7	Customer Advances	CAD	Sales	0	-16	0	-5	-16	-5	-6	-1	-4
8	Other Working Capital	RCWO	Pres Rev, Rev	223	1,465	86	567	1,688	653	763	94	178
9	**Total**	**MISC**		325	2,657	138	1,124	**2,982**	**1,262**	**1,449**	**95**	**177**
	Working Cash											
10	Purchase Gas Exp - Commodity	WC11	Sales	0	-367	0	-113	-367	-113	-143	-23	-88
11	Purchase Gas Exp - Demand	WC12	Design Day	0	-60	0	-27	-60	-27	-33	0	0
12	Labor - Regular	WC13	Oper & Maint	(0)	-7	0	-3	-7	-3	-3	0	-1
13	Labor - Incentive Compensation	WC14	Oper & Maint	(0)	-4	0	-2	-5	-2	-2	0	-1
14	Pension and Benefits	WC15	Labor	(1)	0	-1	0	-2	-1	-1	0	0
15	Payroll Taxes	WC16	Labor	(0)	0	0	0	-1	0	0	0	0
16	Other Operating Expenses	WC17	Oper & Maint	(1)	-16	0	-6	-17	-7	-7	-1	-2
17	Property Taxes	WC18	Ongl Plant	(47)	-17	-31	-11	-64	-42	-20	-1	-1
18	Gross Receipts Tax	WC19	Fees, Rev	0	-13	0	-5	-13	-5	-6	-1	-1
19	Federal Income Tax	WC20	Rt Bas w/o WC	(2)	-1	-1	0	-2	-1	-1	0	0
20	State Income Tax	WC21	Rt Bas w/o WC	(0)	0	0	0	0	0	0	0	0
21	State Sales Tax	WC22	Pres Rev, Rev	(1)	-9	-1	-4	-11	-4	-5	-1	-1
22	**Total Working Cash**	**WCASH**		(54)	-495	-20	-186	**-549**	**-206**	**-221**	**-27**	**-95**
23	**Total Additions**	**ADDIT**		(20)	6,002	-7	2,021	**5,982**	**2,014**	**2,675**	**299**	**994**
24	**Total Rate Base**	**BASE**		28,282	14,116	17,347	8,658	**42,398**	**26,006**	**13,831**	**764**	**1,797**
25	Customer Component							28,282	20,714	7,136	306	126
26	Capacity Component							9,542	3,886	4,822	156	677
27	Commod Component							7,924	1,406	1,877	302	995

Operating Revenue (Cal Month)

	Retail Revenue	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	**Present Retail Rev**	**R01**	**Direct**	8,262	60,579	3,197	23,440	**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
2	**Proposed Retail Rev**	**R01P**	**Direct**	8,963	61,152	3,525	24,052	**70,115**	**27,577**	**30,886**	**3,939**	**7,713**
3	Gross Reciept taxes	R04	**Direct**	0	0	0	0	**0**	0	0	0	0
4	Proposed Transportation	R05	Net Plant	0	0	0	0	0	0	0	0	0
5	Interdepart'l - Angus Anson	R06	Design Day	0	0	0	0	0	0	0	0	0
4	**Total Rate Rev. Present**	**R10**		8,262	60,579	3,197	23,440	**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
	Other Operating Rev											
8	Late Pay Penalties	R21	Present Revenues	0	131	0	51	131	51	59	7	14
9	Penalties - Non-Curtailment	R22	Sales	0	0	0	0	0	0	0	0	0
10	Connection Charges	R23	Customers	45	0	38	0	45	38	7	0	0
11	Return Check Charges	R24	Customers	2	0	2	0	2	2	0	0	0
12	Gross Reciept Taxes	R25	Direct	0	979	0	403	979	403	446	62	67
13	Gas Agreement	R28	Design Day	0	26	0	12	26	12	14	0	0
14	Locating Services	R29	Dist Expen	0	0	0	0	0	0	0	0	0
15	Balancing Services	R30	Sales	0	30	0	9	30	9	12	2	7
16	Ltd Firm Sales - Rsrvs & Vols	R31	Design Day	0	37	0	17	37	17	20	0	0
17	Standy Sales - Resrvs & Vols	R32	Design Day	0	0	0	0	0	0	0	0	0
18	LP Sales to Others - MN	R33	Design Day	0	0	0	0	0	0	0	0	0
19	Off-System Sales	R34	Design Day	0	0	0	0	0	0	0	0	0
20	Opportunity Sales	R35	Design Day	0	1,475	0	658	1,475	658	817	0	0
21	Contr In Aid Cons Tax Gross-Up	R36	CWIP	0	0	0	0	0	0	0	0	0
22	Other - Miscellaneous	R37	DsnDay+Sales	0	41	0	15	41	15	19	1	5
23	**Tot Other Op - Present**	**R20**		47	2,719	20	1,185	**2,766**	**1,205**	**1,395**	**73**	**93**
26	**Tot Oper Rev - Present**	**R00**		8,309	63,298	3,231	24,612	**71,607**	**27,842**	**32,509**	**3,918**	**7,338**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Commodity	OXPGE	Direct	0	47,130	0	16,607	47,130	16,607	20,834	3,272	6,417
2	Demand	OXPGD	Direct	0	8,695	0	3,871	8,695	3,871	4,824	0	0
3	Other Purchased Gas	OXOPG	Sales	0	0	0	0	0	0	0	0	0
4	Opportunity Sales	OXOSN	Design Day	0	1,424	0	636	1,424	636	788	0	0
5	Limited Firm	OXANG	Design Day	0	18	0	8	18	8	10	0	0
6	**Total Purchases**	**OXPG**		0	57,267	0	21,122	**57,267**	**21,122**	**26,456**	**3,272**	**6,417**
	Other Production Exp											
7	Gas Agreement - NSP(W)	OXOSA	Design Day	0	0	0	0	0	0	0	0	0
8	MGP	OXOSSN	Sales	0	360	0	111	360	111	140	23	87
9	Misc LPG Op Exp	OXLPN	Design Day	0	143	0	64	143	64	79	0	0
10	Misc. LNG Op Exp	OXLPM	DsnDay+Sales	0	221	0	83	221	83	104	7	27
11	**Total Other Prod Exp**	**OXOP**		0	724	0	258	**724**	**258**	**323**	**30**	**113**
	Other Transmission Expense											
12	Other Trans Expense	OX30	Average and Peak	0	98	0	38	98	38	47	2	9
	Distribution Expense											
13	Regulator Stations	OX41	Average and Peak	0	42	0	16	42	16	20	1	4
14	Mains	OX42	Mains overall	192	85	136	60	277	196	70	2	8
15	Services	OX43	Serv Study	203	0	151	0	203	151	48	2	1
16	Meters	OX44	Meter Study	225	0	100	0	225	100	115	7	3
17	House Regulators	OX45	Regul Study	28	0	18	0	28	18	9	0	0
18	Other Property & Equip	OX46	Customers	1	0	1	0	1	1	0	0	0
19	Dispatching	OX47	DsnDay+Sales	0	86	0	32	86	32	40	3	10
20	Customer Installations	OX48	Customers	392	0	332	0	392	332	59	1	0
21	Other Distribution	OX49	Customers	240	0	203	0	240	203	36	1	0
22	Supervision & Engineering	OX50	DisExp w/o Sup	146	24	102	17	170	119	45	2	3
23	**Total Distribution**	**OX40**		1,427	237	1,003	167	**1,664**	**1,169**	**445**	**19**	**31**

Operation & Maintenance (Pg 2 of 2)

	Customer Accounting	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Customer Billing Exp	OXBE	Customers	1,142	0	967	0	1,142	967	172	3	1
2	Customer Acct Exp	OXCA	Customers	58	0	49	0	58	49	9	0	0
3	Customer Service & Info	OXSI	Customers	22	0	19	0	22	19	3	0	0
4	**Total**	**OXCASI**		1,222	0	1,034	0	**1,222**	**1,034**	**184**	**3**	**1**
	Admin & General											
5	Property Insurance	OXAGPI	Net Plant	37	10	24	7	47	31	14	1	1
6	Pension and Benefits - ESOP	OXAGPS	Labor	0	0	0	0	0	0	0	0	0
7	Pension and Benefits - Direct	OXAGBL	Labor	414	126	284	86	540	370	143	13	14
8	Incentive Compensation	OXAGB	Labor	76	23	52	16	99	68	26	2	3
9	Injuries and Claims	OXAGID	Plant+Reven	0	115	0	60	115	60	44	4	7
10	Regulation Expense	OXAGR	Pres Rev, Rev	2	15	1	6	17	7	8	1	2
11	Promotional Adv / Contrib Adj	OXADV	Plant+Reven	0	36	0	19	36	19	14	1	2
12	Direct Assigned	OXDIR	Plant+Reven	0	191	0	99	191	99	73	6	12
13	Misc Labor Adjustments	OXAGBS	Labor	337	102	231	70	439	301	116	10	11
14	Non-Regulated Exp Credits	OXCRED	Plant+Reven	0	-26	0	-13	-26	-13	-10	-1	-2
15	**Total A & G Expense**	**OXAG**		866	592	559	382	**1,458**	**941**	**429**	**37**	**51**
	Amortizations											
16	CIP / DSM Amortization	OXCIP	Sales MCF	0	0	0	0	0	0	0	0	0
17	MN Energy Policy Rider	OXCLN	Sales MCF	0	0	0	0	0	0	0	0	0
18	Rate Case Exp Amort	RCA	Pres Rev, Rev	3	17	1	7	20	8	9	1	2
19	Inc Tax Defer Inter Amort	ITDA	Rt Bas w/o WC	0	0	0	0	0	0	0	0	0
20	Project 2000 Amortization	P2A	Plant+Reven	0	0	0	0	0	0	0	0	0
21	**Total Amortizations**	**OXC**		3	17	1	7	**20**	**8**	**9**	**1**	**2**
	Sales Expense											
22	Gross Sales Expense	OXSALX	Sales Exp Study	0	131	0	57	131	57	10	53	11
23	Sales Expen Exlcusions	OXSEE	Sales Exp Study	0	0	0	0	0	0	0	0	0
24	Economic Develop @50%	OXSED	DsnDay+Sales	0	0	0	0	0	0	0	0	0
25	Other Misc - TBT	OXTBT	Net Plant	0	0	0	0	0	0	0	0	0
26	**Total**	**OXSE**		0	131	0	57	**131**	**57**	**10**	**53**	**11**
27	**Total O&M Expense**	**OXT**		3,517	59,065	1,384	23,243	**62,582**	**24,627**	**27,903**	**3,417**	**6,635**

Book Depreciation

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	DX10	Design Day	0	37	0	17	37	17	20	0	0
	Storage Plant											
2	LNG Storage	DX20	Design Day	0	64	0	29	64	29	35	0	0
	Transmission Plant											
6	Transmission Plant	DX30	Average and Peak	0	95	0	37	95	37	46	2	9
	Distribution Plant											
7	Regulator Stations	DX41	Average and Peak	0	18	0	7	18	7	9	0	2
8	Mains	DX42	Mains overall	645	286	456	202	931	658	236	8	28
9	Services	DX43	Serv Study	580	0	433	0	580	433	138	7	2
10	Meters	DX44	Meter Study	318	0	141	0	318	141	163	9	4
11	House Regulators	DX45	Regul Study	21	0	13	0	21	13	7	0	0
12	Lakes Area Surcharge	DX46	Dist Plant	0	0	0	0	0	0	0	0	0
13	**Total**	**DX40**		**1,563**	304	1,049	204	**1,867**	**1,252**	**553**	**25**	**37**
14	**Depreciation Expense w/o Com & Gen**	**DX60**		**1,563**	500	1,011	323	**2,063**	**1,335**	**655**	**27**	**47**
	General Plant											
14	General Plant	**DX70**	DX60	84	27	54	17	**111**	**72**	**35**	**1**	**3**
	Common Plant											
19	Common Plant	**DX80**	DX60	397	127	257	82	**524**	**339**	**166**	**7**	**12**
24	**Total Book Deprec**	**DX00**		**2,044**	654	1,323	423	**2,698**	**1,745**	**857**	**35**	**61**

Real Estate & Property Taxes

	Production Plant-	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PT10	Design Day	0	37	0	16	37	16	20	0	0
	Storage Plant											
2	LNG Storage	PT20	Design Day	0	75	0	34	75	34	42	0	0
	Transmission Plant											
3	Transmission Plant	PT30	Average and Peak	0	37	0	15	37	15	18	1	4
	Distribution Plant											
4	Regulator Stations	PT41	Average and Peak	0	8	0	3	8	3	4	0	1
5	Mains	PT42	Mains overall	292	129	206	91	421	298	107	4	13
6	Services	PT43	Serv Study	290	0	216	0	290	216	69	3	1
7	Meters	PT44	Meter Study	112	0	50	0	112	50	57	3	2
8	House Regulators	PT45	Regul Study	13	0	9	0	13	9	5	0	0
9	Other Prop & Equip	PT46	Dist Plant	0	0	0	0	0	0	0	0	0
10	**Total**	PT40		707	137	482	93	**844**	**575**	**242**	**11**	**17**
11	Real Est & Prop Taxes w/o Gen & Com	PT60		707	286	455	184	**993**	**640**	**322**	**11**	**20**
	General Plant											
18	General Plant	PT70	PT60	2	1	1	0	**2**	**2**	**1**	**0**	**0**
	Common Plant											
23	Common Plant	**PT80**	PT60	5	2	3	1	**7**	**5**	**2**	**0**	**0**
24	**Tot RI Est & Pr Tax**	**PT0**		714	289	460	186	**1,002**	**646**	**325**	**11**	**20**
25	Gross Earnings Tax	GETX	Direct	0	979	0	403	979	403	446	62	67
26	Payroll Taxes	Z00	Labor	125	38	86	26	163	112	43	4	4
27	**Tot Non-Income Taxes**	**PTOT**		839	1,306	454	707	**2,144**	**1,161**	**814**	**78**	**92**

Provision For Deferred Income Taxes

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PR10	Design Day	0	-3	0	-1	-3	-1	-2	0	0
	Storage Plant											
2	LNG Storage	PR20	Design Day	0	21	0	9	21	9	12	0	0
	Transmission Plant											
3	Transmission Plant	PR30	Average and Peak	0	83	0	33	**83**	33	40	2	8
	Distribution Plant											
4	Regulator Stations	PR41	Average and Peak	0	5	0	2	5	2	3	0	1
5	Mains	PR42	Mains overall	198	87	140	62	285	201	72	3	9
6	Services	PR43	Serv Study	196	0	146	0	196	146	47	2	1
7	Meters	PR44	Meter Study	76	0	34	0	76	34	39	2	1
8	House Regulators	PR45	Regul Study	9	0	6	0	9	6	3	0	0
9	**Total**	**PR40**		478	93	326	63	**571**	**389**	**163**	**7**	**11**
10	**Provision w/o Gen & Com**	PR60			672	0	430	672	430	214	9	19
	General Plant											
11	General Plant	PR70	PR60	(14)	-5	-9	-4	**-19**	-12	-6	0	-1
	Common Plant											
22	Common Plant	PR80	PR60	32	13	20	8	**45**	29	14	1	1
	Other											
29	All Other Adjustments	PR77	Labor	(90)	-27	-62	-19	-117	-80	-31	-3	-3
	Total Other	**PR70**			-117	0	-80	**-117**	**-80**	**-31**	**-3**	**-3**
30	**Tot Prov For Defer**	**PR0**		407	174	257	110	**581**	**366**	**191**	**7**	**17**

Investment Tax Credit For Current Income

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	CI10	Design Day	0	0	0	0	0	0	0	0	0
	Storage Plant											
2	LNG Storage	CI20	Design Day	0	-1	0	0	-1	0	-1	0	0
	Transmission Plant											
3	Transmission Plant	CI30	Average and Peak	0	-2	0	-1	-2	-1	-1	0	0
	Distribution Plant											
6	Regulator Stations	CI41	Average and Peak	0	0	0	0	0	0	0	0	0
7	Mains	CI42	Mains overall	(9)	-4	-6	-3	-13	-9	-3	0	0
8	Services	CI43	Serv Study	(10)	0	-7	0	-10	-7	-2	0	0
9	Meters	CI44	Meter Study	(4)	0	-2	0	-4	-2	-2	0	0
10	House Regulators	CI45	Regul Study	(0)	0	0	0	0	0	0	0	0
11	**Total**	**CI40**		(23)	-4	-15	-3	**-27**	**-18**	**-8**	**0**	**-1**
12	ITC w/o gen and Com	CI60	subtotal	(23)	-7	-15	-5	**-30**	**-20**	**-9**	**0**	**-1**
	General Plant											
13	General Plant	CI70	CI60	0	0	0	0	**0**	**0**	**0**	**0**	**0**
	Common Plant											
14	Common Plant	CI80	CI60	0	0	0	0	**0**	**0**	**0**	**0**	**0**
15	**Tot ITC For Curr Inc**	**CI00**		(23)	-7	-15	-5	**-30**	**-20**	**-9**	**0**	**-1**
16	**Gross Inv Tax Credit**	**DI5**		0	0	0	0	**0**	**0**	**0**	**0**	**0**
17	**Net Inv Tax Credit**	**DI00**		(23)	-7	-15	-5	**-30**	**-20**	**-9**	**0**	**-1**
18	**Total Operating Exp**	**TOE**		6,784	61,191	2,783	25,097	**67,975**	**27,880**	**29,755**	**3,536**	**6,804**
19	**Op Inc Before Inc Tax**	**OPY**		1,524	2,107	-16	-22	**3,632**	**-38**	**2,753**	**382**	**534**

Tax Depreciation & Removal Exp Generated

	Production Plant	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	TA10	Design Day	0	36	0	16	36	16	20	0	0
	Storage Plant											
2	LNG Storage	TA20	Design Day	0	118	0	53	118	53	65	0	0
	Transmission Plant											
3	Transmission Plant	TA30	Average and Peak	0	317	0	124	**317**	124	154	7	31
	Distribution Plant											
7	Regulator Stations	TA41	Average and Peak	0	34	0	13	34	13	16	1	3
8	Mains	TA42	Mains overall	1,261	559	892	395	1,820	1,287	462	16	56
9	Services	TA43	Serv Study	1,252	0	934	0	1 252	934	299	14	5
10	Meters	TA44	Meter Study	483	0	215	0	483	215	248	14	7
11	House Regulators	TA45	Regul Study	58	0	37	0	58	37	20	0	1
12	Other Property & Equip	TA46	Dist Plant	0	0	0	0	0	0	0	0	0
13	**Total**	**TA40**		3,054	593	2,082	404	**3,647**	**2,486**	**1,044**	**45**	**71**
14	**Tax Depreciation w/o Gen & Com**	**TA60**	Subtotal	3,054	1,064	1,987	692	**4,118**	**2,679**	**1,284**	**53**	**103**
	General Plant											
14	General Plant	TA70	TA60	81	28	53	18	**109**	**71**	**34**	**1**	**3**
	Common Plant											
23	Common Plant	TA80	TA60	417	145	271	94	**562**	**366**	**175**	**7**	**14**
24	Tax Benefit Transfers	TATBT	Net Plant	(97)	-28	-64	-18	-125	-82	-38	-2	-3
25	**Total Tax Depreciation**	**TA00**		3,455	1,209	2,247	786	**4,664**	**3,033**	**1,454**	**60**	**117**

Present Return

	Inc Tax Additions	Input	Alloc	Total ND Cust	Total ND Other	Res Cust	Res Other	ND	Res	Sm C/I	Sm Int	Lg Int
1	Total Book Depr Exp	DX00		2,044	654	1,323	423	2,698	1,745	857	35	61
2	Book Dep Cleared To Operating	DX99	Book Deprec	59	19	38	12	78	50	25	1	2
3	Provision for Deferred	PRO		407	174	257	110	581	366	191	7	17
4	Net Inv Tax Credit	DI00		(23)	-7	-15	-5	-30	-20	-9	0	-1
5	Book Amortizations	NDDI	Net Plant	16	4	10	3	20	13	6	0	0
6	Connect Fees and Other	ND2B	Customers	81	0	69	0	81	69	12	0	0
7	Avoided Tax Interest	ND2ASP	CWIP	0	106	0	47	106	47	58	0	1
8	Tax Capitalized Leases	NDTC	Plant	0	0	0	0	0	0	0	0	0
9	Meals & Entertainment	NDME	Labor	2	1	2	0	3	2	1	0	0
10	TBT Net Expense	NDTBT	Net Plant	0	0	0	0	0	0	0	0	0
11	**Total Tax Additions**			2,586	951	1,662	611	**3,537**	**2,273**	**1,140**	**43**	**81**
	Inc Tax Deductions											
12	Tax Depr & Removal Exp	TA00		3,455	1,209	2,247	786	4,664	3,033	1,454	60	117
13	Debt Interest Expense	ND1	Rate Base	1,033	516	634	316	1,548	950	505	28	66
14	Other Timing Differerences	PRMPAG	Labor	(58)	-17	-39	-12	-75	-51	-20	-2	-2
15	Net Preferred Stock Deduction	OTHLHD	Net Plant	0	0	0	0	0	0	0	0	0
16	**Total**			4,430	1,707	2,838	1,093	**6,137**	**3,932**	**1,940**	**86**	**180**
17	**Taxable Net Income**	FSNI		(320)	1,351	526	-2,222	**1,031**	**-1,696**	**1,954**	**339**	**434**
18	**Inc Tax (Pre-Credits), @39 55%**	TAX		(126)	534	208	-879	**408**	**-671**	**773**	**134**	**172**
19	**Tax Credits**				0	0	0	0	0	0	0	0
20	**Fed & State Inc Tax**	**TAXES**		(126)	534	208	-879	**408**	**-671**	**773**	**134**	**172**
21	**Total AFUDC**	**AFC**	**CWIP**	0	0	0	0	**0**	**0**	**0**	**0**	**0**
22	**Pres Return**	**RETR**	**,BASE**	1,651	1,573	324	309	**3,224**	**633**	**1,980**	**248**	**362**
23	**Pres Return on Rate Base**	**RTRT**		5 84%	1 77%	0	0	**7.60%**	**2 43%**	**14 32%**	**32 43%**	**20 16%**

Labor Allocator

336,490

	Labor Components	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
24	Customer Billing	LAB1	Wtd Customer	3 4%	2 8%	0 5%	0 1%	0 0%
25	Customer Accounting	LAB2	Customer	10 8%	9 2%	1 6%	0 0%	0 0%
26	Cust Serv & Inform	LAB3	Customer	2.3%	2 0%	0 3%	0 0%	0 0%
27	Distribution	LAB4	Dist Expen	70 2%	49 3%	18 8%	0 8%	1 3%
28	Gas Storage - LNG	LAB5	DsnDay+Sales	5 4%	2 0%	2 5%	0 2%	0 6%
29	Production	LAB6	Other Produc	2 6%	0 9%	1 1%	0 1%	0 4%
30	Sales	LAB7	Sales Exp Study	2 9%	1 3%	0 2%	1 2%	0 2%
31	Transmission	LAB8	Design Day	2 4%	1.1%	1.4%	0.0%	0.0%
32	**Total**	LABOR		100 0%	68 6%	26 5%	2 3%	2 6%

EXTERNAL ALLOCATORS				ND	Res	Sm C/I	Sm Int	Lg Int
Customer Related								
1 Customers - B Basis	C10	40,827		40,827	34,553	6,141	110	23
%1 Customers - B Basis	C10			100 00%	84 63%	15 04%	0 27%	0 06%
2 Service Weighting (index)	C20				1 00	1 80	4 75	8 19
2 Weighted Service	C20			46,318	34,553	11,054	523	188
%2 Services Factor	C20			100 00%	74 60%	23 87%	1 13%	0 41%
3 Meter Factor Weighting (Index)	C21				1 00	6 48	20 47	45 95
3 Weighted Meter	C21			77,659	34,553	39,794	2,255	1,057
%3 Meter Factor	C21			100 00%	44 49%	51 24%	2 90%	1 36%
4 House Regulator Weighting (index)	C22				1 00	2 95	3 79	30 84
4 Weighted Regulator				53,817	34,553	18,138	418	709
%4 House Regulator Factor	C22			100 00%	64 20%	33 70%	0 78%	1 32%
5 Sale expense Weighting	E03				0 000762	0 000762	0 222279	0 222279
5 Weighted Sales Expense	E03			61	26	5	24	5
%5 Sales Expense	E03			100 00%	43 44%	7 72%	40 40%	8 44%
6 Cust Acctg Weights	C10WTS			23	1	1	6	6
6 Weighted Customers	C10W			41,493	34,553	6,141	661	138
%6 Weighted Custs (Cust Acctg)	C10W			100 000%	83 274%	14 800%	1 593%	0 333%
Main Allocator								
Mains - Average Day (Sales)				26,819	8,270	10,411	1,689	6,448
Mains - Average Day (Sales)	Load Factor =			100 00%	30 84%	38 82%	6 30%	24 04%
(Transportation adder)								
Mains - Excess Design Day				56,828	24,971	30,809	0	############
Mains - Excess Design Day				100 00%	43 94%	54 22%	0 00%	1 84%
Mains Average and Peak				9,227	3,619	4,491	209	908
Average and Peak				100 00%	39 22%	48 67%	2 27%	9 84%
Mains overall				30,055	21,246	7,624	266	920
Mains overall				100 00%	70 69%	25 37%	0 88%	3 06%
Sales and Capacity Related								
6 Design Day	D10			74,462	33,242	41,220	0	0
%6 Design Day %	D10			100 00%	44 64%	55 36%	0 00%	0 00%
7 Sales MCF	E10			9,788,919	3,018,662	3,800,041	616,604	2,353,612
%7 Sales MCF	E10			100 00%	30 84%	38 82%	6 30%	24 04%
8 Sales MCF (Exc CIP exempt)	E10CIP			8,948,819	3,018,662	3,800,041	616,604	1,513,512
%8 Sales MCF	E10CIP			100 00%	33 73%	42 46%	6 89%	16 91%
9 Gross Receipts	GR10			1,068,746	440,304	486,820	68,064	73,558
%9 Gross Receipts	GR10			100 00%	41 20%	45 55%	6 37%	6 88%
%10 CIP Allocator	GR10			3,346	0	0	0	0
CIP Allocator	GR10			0 00%	0 00%	0 00%	0 00%	0 00%
11 LatePayment Revenues	LPY							
%11 LatePayment Revenues	LPY			100 00%	38 69%	45 20%	5 59%	10 52%
12 Present Rev				68,841	26,637	31,114	3,845	7,245
%12 Present Rev	R01			100 00%	38 69%	45 20%	5 59%	10 52%

	INTERNAL ALLOCATORS		ND	Res	Sm C/I	Sm Int	Lg Int
1	Rate Base		42,398	26,006	13,831	764	1,797
%1	Rate Base	BASE-COL	100 000%	61 338%	32 622%	1 802%	4 238%
				100 000%	100 000%	100 000%	100 000%
2	Rate Base less Working Cash		39,965	24,950	12,603	696	1,715
%2	Rate Base less Working Cash	BASEWC	100 000%	62 431%	31 536%	1 742%	4 291%
			101	44	55	0	1
4	Construction Work In Progress	CWIP	100 000%	44 052%	54 629%	0 247%	1 072%
5	50% Design Day, 50% Energy	D10E10	100 000%	37 740%	47 089%	3 149%	12 022%
7	Book Depreciation	DX00	100 000%	64 694%	31 755%	1 295%	2 256%
8	50% Gross Plant, 50% Pres Rev	EGPRV	100 000%	51 896%	38 360%	3 393%	6 350%
9	Gas Plant In Service	GPIS	100 000%	65 099%	31 524%	1 201%	2 176%
9	Gas Plant In Service (w/o Gen and Common)	GPIS (B)	100 000%	65 099%	31 524%	1 201%	2 176%
10	Labor	LABOR	100 000%	68 567%	26 504%	2 325%	2 605%
11	Net Gas Plant In Svc (w/o TBT)	NGPIS(A)	100 000%	65 899%	30 631%	1 265%	2 205%
12	Dis O&M w/o Sup & Misc	OXDTS	1,494	1,050	400	17	28
12	Dist O&M (w/o Sup & Eng)	OX40(A)	100 000%	70 260%	26 746%	1 128%	1 845%
13	Other Production Expense	OXOP	100 000%	35 671%	44 610%	4 093%	15 625%
14	Oper & Maint Expense	OXT	100 000%	39 351%	44 586%	5 460%	10 602%
15	Distribution Plant	P40	100 000%	68 166%	28 628%	1 246%	1 959%
4	Transmission & Distribution	TD	63,373	42,290	18,772	822	1,489
4	Transmission & Distribution	TD	100 000%	66 731%	29 622%	1 297%	2 349%
17	Rev w/o Regul Exp, Col %'s	R02-COL	100 000%	41 918%	42 944%	5 137%	10 001%

CONSTANTS FOR REV CALCULATION

			Rate	Ratio	Wtd Cost
1	Long Term Debt		7 3300%	48 6530%	3 5663%
2	Short Term Debt		7.7400%	1.1070%	0.0857%
3	Debt Total		7 3392%	49 7600%	3 6520%
4	Preferred Stock		0 0000%	0 0000%	0 0000%
5	Common Equity		11.5000%	50.2400%	5.7776%
6	Required Rate of Return			100 0000%	9 4296%
7	MN Combined State & Fed Tax Rate	TAXRATE	0 3955000		
8	1 / (1 - Tax Rate) Factor	ONEOVER	1 6542600		
9	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	0 6542600		

APPROVED
DATE: 3-23-05
KMF

MOTION

March 23, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission acknowledge the March 9, 2005 issuance of a Notice of Informal Hearing and Notice of Cancellation of Formal Hearing in Northern States Power Company's Natural Gas Rate Increase application, Case No. PU-04-578

AB

☐ Proprietary
☒ Non-Proprietary

Northern States Power Company
Docket No. PU-400-04-578
Response To Patrick Fahn Information Request No. 3-03
Date Received: 3/8/05

Question:
How much variability within each customer type is there in the equipment and/or facilities used to deliver natural gas?

Response:
As shown in the table below, the variability in natural gas delivery equipment within the residential customer class is low, while a wide variety of metering and service line equipment exists among the Company's commercial and industrial customers in North Dakota.

Customer Class	Meter	Service Lines
Residential Firm	Diaphragm **250** size meter is used for the vast majority (>99%) of residential customers. **400** size meter may be installed in rare circumstances (2-4 homes out of about 1,500 average new premises in ND each year) for extremely large homes (roughly in excess of 7,000 square feet)	**5/8"** service pipe is installed for the vast majority (>99%) of residential services **1"** service pipe may be installed for extremely large homes (roughly in excess of 7,000 square feet) with significant loads in medium pressure areas on the system, or unusually long service connection distances.
Commercial and Industrial	Diaphragm[1] Meters. **250** (loads up to 300 cubic feet per hour – CFH) **400** size (300 to 900 CFH) **1,000** size (1,000 to 2,800 CFH) Rotary Meters. **3 M** (loads from 2,800 to 3,300 CFH) 5 M, 7 M, and 11 M rotary meters are also used in commercial applications for progressively larger loads	5/8", 1", 1¼", 2", 4", or 6" service pipes

Notes:
- Meter size (250, 400, 1000, etc.) roughly correlates to the rate of flow that can be accommodated by the meter For example, a 250 size diaphragm meter can be used for loads up to about 250-300 cubic feet per hour (depending on distribution system pressure).

- There is very little cost differential between the 5/8" and the far less common 1" diameters of service pipe installed for residential customers -- approximately $15 to $25 for a 100 foot installed service However, the varying pipe diameters used in commercial applications may create material cost differences, though differences in the type and installation of the meter will have the most impact on cost. The typical installed cost of a 250 size meter set (meter, regulator, riser, rack) is about $200 and the typical cost of a 400 size meter set is about $300.

- O&M costs do not vary materially between the different service line and meter configurations.

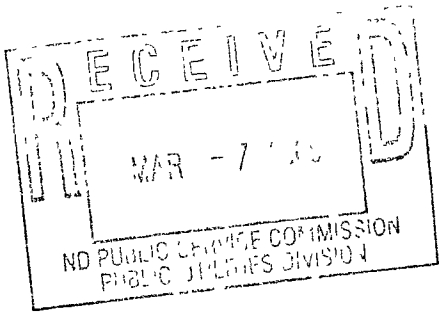
[1] Xcel Energy has also installed 600 and 800 diaphragm meters in the past, but no longer purchases or installs meters of that size

---

Response By:	John Ness
Title:	Sr. Specialty Engineer
Department:	ND Gas Engineering
Telephone:	701-241-8695
Date:	3/11/05

LARKIN & ASSOCIATES, PLLC

CERTIFIED PUBLIC ACCOUNTANTS
15728 FARMINGTON ROAD
LIVONIA, MICHIGAN 48154
PHONE (734) 522-3420
FAX (734) 522-1410



March 1, 2005

Mr. Jerry Lein
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

NSP-ND Gas Cost of Capital, Case No. PU-04-578
Billing for Professional Services Rendered through February 27, 2005.

	Hours		Hourly Rate	Total Amount
Hugh Larkin, Jr.	0.0	@	$ 125.00	$ -
Helmuth W. Schultz	0.0	@	$ 115.00	$ -
Aaron Rothschild	142.0	@	$ 85.00	$ 12,070.00
Ralph C. Smith	6.0	@	$ 115.00	$ 690.00
Donna M. DeRonne	0.0	@	$ 115.00	$ -
Christine Miller	0.0	@	$ 65.00	$ -
Mark S. Dady	0.0	@	$ 65.00	$ -
Word Processing/Clerical	0.0	@	$ 20.00	$ -
Total Professional	148.0			$ 12,760.00
Expenses (See attached detail)				$ -
Total Amount				$ 12,760.00

77000
dc1
24578(a1)

O K
Will
3-11-05

NSP-ND Gas

February 2005 Summary (01/31/05 - 02/27/05)

Name	Date	Client	Company	Work Description	Hours	Expenses
R Smith	01/31/05	ND PSC	NSP-ND Gas	Coordination of work effort	0 5	
R Smith	02/07/05	ND PSC	NSP-ND Gas	Read and send DR on cost of capital	0 5	
R Smith	02/09/05	ND PSC	NSP-ND Gas	Work coordination/project supervision	0 5	
R Smith	02/14/05	ND PSC	NSP-ND Gas	Emails re work, project management	0 5	
R Smith	02/21/05	ND PSC	NSP-ND Gas	Read and mark comments on AR draft testimony	2 5	
R Smith	02/23/05	ND PSC	NSP-ND Gas	Project management	1 0	
R Smith	02/25/05	ND PSC	NSP-ND Gas	Email NSP discovery responses to Aaron, provide mailing address to NSP	0 5	
				Total Hours	6 0	

A Rothschild	1/30/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	8	
A Rothschild	1/31/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	8	
A Rothschild	2/1/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	8	
A Rothschild	2/2/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	4	
A Rothschild	2/3/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	6	
A Rothschild	2/4/05	ND PSC	NSP-ND Gas	Prepare Interrogatories	3	
A Rothschild	2/7/05	ND PSC	NSP-ND Gas	Prepare Schedules	10	
A Rothschild	2/8/05	ND PSC	NSP-ND Gas	Prepare Schedules	6	
A Rothschild	2/10/05	ND PSC	NSP-ND Gas	Prepare Schedules	2	
A Rothschild	2/11/05	ND PSC	NSP-ND Gas	Prepare Schedules	4	
A Rothschild	2/14/05	ND PSC	NSP-ND Gas	Prepare Schedules	8	
A Rothschild	2/15/05	ND PSC	NSP-ND Gas	Prepare Schedules	8	
A Rothschild	2/16/05	ND PSC	NSP-ND Gas	Prepare Testimony	8	
A Rothschild	2/17/05	ND PSC	NSP-ND Gas	Prepare Testimony	10	
A Rothschild	2/18/05	ND PSC	NSP-ND Gas	Prepare Testimony	8	
A Rothschild	2/21/05	ND PSC	NSP-ND Gas	Prepare Testimony	8	
A Rothschild	2/22/05	ND PSC	NSP-ND Gas	Prepare Testimony	8	
A Rothschild	2/23/05	ND PSC	NSP-ND Gas	Prepare Testimony	6	
A Rothschild	2/24/05	ND PSC	NSP-ND Gas	Prepare Testimony	5	
A Rothschild	2/25/05	ND PSC	NSP-ND Gas	Edit Testimony	8	
A Rothschild	2/27/05	ND PSC	NSP-ND Gas	Edit Testimony	6	
				Total Hours	142 0	

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **10th day of March, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Informal Hearing and Notice of Cancellation of Formal Hearing

The envelopes were addressed as follows.

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747
Cert. No. 7003 2260 0001 3517 9657

Kent T Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Mineapolis MN 55401
Cert. No. 7003 2260 0001 3517 9664

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3517 9671

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **10th day of March, 2005**

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **10th day of March, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Notice of Informal Hearing and Notice of Cancellation of Formal Hearing

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **10th day of March, 2005**.

Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

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F James Moriarty
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Steven Tomac
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St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
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Elk River MN 55330-0800

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Jerry Tuchscherer
Grand Forks Board of Realtors
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Grand Forks ND 58201-6761

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

Karyn Grass
IPAMS
6620 Denver Club Bldg 518 17th St
Denver CO 80202-4167

KHRT AM
PO Box 1210
Minot ND 58702-1210

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KNOX-AM & KRRK-FM
PO Box 13638
Grand Forks ND 58208-3638

KTHI-TV
PO Box 12427
Grand Forks ND 58208-2427

Bruce Imsdahl
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Helbling, Sharon D.

From: Helbling, Sharon D
Sent: Thursday, March 10, 2005 7 26 AM
To: ndna
Subject: Notice of Informal Hearing, Case No PU-04-578

Colleen Park
North Dakota Newspaper Association

Colleen,

Please have the attached Notice of Informal Hearing published as a legal publication in the next issue of the Fargo Forum and the Grand Forks Herald, and run it as a "News Item Only" article as well

Send the bill to the Public Service Commission, along with a tear sheet for billing purposes.

If you have any questions, let me know

Thank you

Sharon Helbling
Public Utilities Division

3-9-05
of Informal

68 **PU-04-578** Pages 1

1 Notice e-mailed to NDNA requesting publication by Public Service Commission

03/09/2005 C Comm Legal PUD (4) Mike ALJ

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power company
Natural Gas Rate Increase
Application

Case No. PU-04-578

NOTICE OF INFORMAL HEARING and NOTICE OF CANCELLATION OF FORMAL HEARING

March 9, 2005

On November 2, 2004, Northern States Power Company (NSP) filed an application to increase its rates for natural gas service.

On February 17, 2005, NSP filed a Settlement Agreement between NSP and Commission Advocacy Staff providing two options for the Commission to consider. Option A provides for a revenue increase of $887,000 or 1.2%. Option A increases the residential and commercial firm service monthly Basic Service Charge, decreases the corresponding volumetric Distribution Charge, and increases the commercial interruptible Distribution Charges. Option B provides for a revenue increase of $745,000 or 1.1% which combines both residential delivery service charges into a flat monthly Delivery Services Charge of $15.69 per month. Rates for commercial firm and interruptible service would be the same as provided in Option A.

A formal hearing was scheduled for April 20, 2005. Instead of the formal hearing an **informal hearing** will be held on **April 20, 2005 at 1:30 p.m. CDT** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. At the informal hearing the applicant and Commission Advocacy Staff will be given an opportunity to present an overview of and justification for the settlement proposal and interested persons will be given an opportunity to be heard. If this matter is not settled the formal hearing will be rescheduled.

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Illona Jeffcoat-Sacco, Executive Secretary, at least 24 hours prior.

PUBLIC SERVICE COMMISSION

Susan E. Wefald	**Tony Clark**	**Kevin Cramer**
Commissioner	**President**	**Commissioner**

Xcel Energy

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

RECEIVED
MAR - 7 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

March 7, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Northern States Power Co. d/b/a Xcel Energy Notice of Change in Rates for Natural Gas Service – Case No. PU-400-04-578 (Settlement Agreement)

Dear Ms. Jeffcoat-Sacco:

In preparation for the upcoming Informal Hearing on March 8, 2005 concerning Case No. PU-400-04-578, Xcel Energy submits this letter and related attachments in support of the Settlement Agreement reached between Advocacy Staff and the Company. Most of this information will be presented at the hearing, but submitting it beforehand gives the Commission and Advisory Staff more time to review the information.

Introduction

Xcel Energy is pleased to have worked with Advocacy Staff to reach an agreeable resolution to the company's $1.3 million, or 1.8%, natural gas rate application. Settlement discussions afforded both the Staff and Company opportunities to freely explore a number of options to address Xcel Energy's revenue shortfall in a creative and efficient manner. The Commission's Settlement Guidelines provide that settlement is a potential outcome in all cases, including rate cases. In this case, the parties reached a consensus on two different rate options ("A" and "B"), allowing the Commission the flexibility to choose the one they prefer. We believe the settlement agreement is consistent with the Commission's settlement guidelines because it leaves the significant policy issue -- the proposed Residential rate design -- for the Commission to decide.

Revenue Requirements

Both the Company and Advocacy Staff agreed to an overall annual revenue increase of $886,493, which is about 69% of the requested amount. It was agreed to substantially reduce the Residential class share of the increase (the Residential increase went from 4.6% in the Company's application to 2.3% in the settlement agreement), and increase the firm Commercial customer class portion of the overall increase (the Commercial - Firm increase went from 0.0% in the Company application to 0.7% in the settlement agreement) .

In addition, the Company is willing to accept an even lower overall revenue increase of $745,192 if Residential delivery revenues would no longer be collected through volumetric Distribution Charges. Because Residential use per customer is declining approximately 2% each year, representing about $60,000 to $70,000 in lost delivery revenues annually, the Company recognizes

that it would not take very long before its gas distribution rates would need to be increased again to offset the lost sales. In other words, Xcel Energy is taking a longer term view in its willingness to accept a lower revenue increase in 2005 in exchange for a rate design we believe will mitigate the adverse impacts of declining use on delivery revenues on a longer term basis.

Because the lower revenue increase is very close to the overall increase currently being collected by the Company through interim rates (the difference is the increase in Returned Check Charges of $4000), both parties recognize that its implementation will have a minimal impact on total costs to customers in 2005.

Rate Design

Perhaps the most significant and beneficial element of the Settlement Agreement is the option (Option B) given to the Commissioners to establish a single, fixed Residential Delivery Services charge in place of the existing Basic Service charge and the usage-based Distribution Charge. There are many benefits for customers, regulators, and the Company in charging customers a fixed monthly fee for their natural gas delivery service in a manner similar to cable TV, local phone service, etc. Schedule 1 lists some of the most important benefits of moving to a single, fixed charge for Residential natural gas delivery services.

Partial Decoupling Mechanism

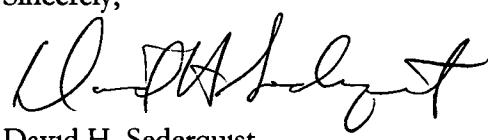
Xcel Energy remains committed to pursuing some form of rate mechanism to offset the adverse impacts of declining Residential use per customer. However, implementing such a mechanism within the Company billing system on a real time basis as desired by the Advocacy Staff, is cost prohibitive at this time. The advantage of the Option "B" rate design is that there should not be a need to address this issue in future rate proceedings, as the Company's Residential distribution revenues would be decoupled from usage.

Attached you will find the following schedules providing additional information relating to the Settlement:

- Schedule 1 (benefits of a single fixed Delivery Services charge for residential customers)
- Schedule 2 (Option "A" summary of revenues, rate schedules, typical bills)
- Schedule 3 (Option "B" summary of revenues, rate schedules, typical bills)
- Schedule 4 (2004 residential average monthly use and bills using current rates, Option "A" rates, and Option "B" rates)

Please call me if you have any questions or comments.

Sincerely,



David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Co. d/b/a Xcel Energy

Enclosures

Northern States Power Co. d/b/a Xcel Energy
Gas Utility – State of North Dakota
Benefits of a Single Residential Fixed Monthly Charge
for Natural Gas Delivery Services

1. Residential customers would no longer overpay for the cost of gas delivery service in colder than normal winters and underpay in warmer than normal winters;
2. Bills would be more stable since 24.1% of the total bill would be fixed each month and not dependent on changes in weather or usage patterns (versus 8.4% currently):
3. Customer bills would be simpler, with a single charge for "Delivery Services" instead of up to three charges: a Basic Service Charge, a Distribution Charge, and potentially a revenue stabilization (partial decoupling) mechanism;
4. Eliminates altogether the need for revenue stabilization mechanisms (such as Xcel Energy's proposed Partial Decoupling Rider or MDU's Distribution Delivery Stabilization Mechanism [DDSM]), which are more difficult to explain to customers, result in regularly changing adjustments (positive and negative), create the potential for error, and may be burdensome to implement and maintain;
5. Over the long term, a single Residential Delivery Services charge should generate fewer consumer complaints and questions for both the Commission and the Company, since decoupling riders and DDSM type charges or credits are not easily understood and will change each month. Moreover, the customer most likely to complain about a high fixed charge may also complain about an adjustment mechanism that results in a similar fixed billing impact – only in a more convoluted manner;
6. Would send better economic signals to customers who request to use Xcel Energy natural gas service only as a *backup* energy source during peak periods, thereby creating higher costs for other Xcel Energy natural gas customers
7. The Commission would be protected from accusations by customers or the public of complicating bills or attempting to "hide" charges (as with an adjustment mechanism or the current bifurcated recovery of delivery services costs);
8. Should extend the length of time between gas rate cases because there would no delivery services revenue loss due to declining use per customer over time.
9. Today, consumers have become more accustomed to fixed monthly bills for cable TV, internet service, local telephone, and garbage pick-up services, among others. A fixed Delivery Services charge for Xcel Energy's local gas pipes would be comparable to the phone company's fixed charge for its local wires (while the wholesale Cost of Gas component would be comparable to long-distance costs);
10. Since roughly 75% - 80% of each residential bill would still be tied to usage (the Cost of Gas component), a strong incentive remains for customers to seek ways to conserve energy; however, the change eliminates any disincentives for Xcel Energy to actively promote energy conservation by gas customers, since the Company's delivery revenues would no longer be adversely impacted by declining customer usage;

11. Company earnings in North Dakota would not be as unpredictable as a result of abnormal weather swings. It would also be easier for the Commission to audit the Company's revenues and earnings, as residential regulated delivery revenues would be directly inked to the number of residential customers on the Company's system;
12. Would mitigate the impact of "Budget Billing" true-ups on customer bills because less of the bill would be subject to the variations of weather and its subsequent impact on usage;
13. Helps to educate consumers about the service/product they are paying for by clearly distinguishing the costs for 1) the natural gas they consume, and 2) the delivery of the gas to their homes or businesses. Consumers will better understand the fixed cost nature of the delivery system vs. the variable cost attributes of the commodity gas itself. Consumers will also better understand the component of their bill that Xcel Energy is responsible for.
14. Provides a better match of revenue with the associated distribution costs, and is therefore a more efficient pricing methodology. In general, the Company provides each residential customer a standard-diameter pipe, regardless of their expected usage. Under current practices, high-usage Residential customers effectively subsidize low-usage customers;
15. Most customers (the middle of the bell-shaped usage curve) won't see much of a change in their overall bill, since the Delivery Services charge is primarily a replacement of both the fixed Basic Service Charge and the variable Distribution Charge. The small group of high-usage customers should favor this change; it will eliminate the subsidy they are paying and lower their bills. The only group that might complain would consist of relatively few low-usage customers, since their bills will rise significantly on a *percentage* basis (although only $4-6$ dollars per month more than the more traditional Option A rate design). But as the previous point explains, low-usage customers (whom are not necessarily low-income) are not currently paying the full cost of their service;
16. Many low-income customers will see their costs reduced. Contrary to common misperception that low-usage customers are also low-income customers, recent studies suggest that personal income level has little predictive relationship regarding gas usage. A poorly insulated or constructed home will need much more gas to heat, and if bills for delivery are based on usage, they will pay more for their service than they would under the monthly Distribution Charge;
17. Avoids customer frustration stemming from the use of a partial decoupling mechanism to address usage-based revenue erosion, whereby surcharges only get larger the more consumers reduce their consumption.
18. Represents a much lower cost method (in terms of customer accounting and billing system IT changes) to achieve the same objective that real-time partial decoupling and DDSM mechanisms are designed to address.

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test year
Settlement Agreement - Comparison of Option "A" and Class Cost of Service Study Results

	Rate Code	Avg Cust.	Dkt Sales	Revenue		Increase	
				Present	Option A	Amount	%
Firm Service							
Residential	401	34,553	3,018,662	$26,361,011	$26,959,966	$598,955	2 3%
Commercial and Industrial	410	6,141	3,800,045	$30,884,941	$31,110,473	$225,532	0 7%
Total Firm Service		**40,694**	**6,818,707**	**$57,245,953**	**$58,070,440**	**$824,487**	**1.4%**
Interruptible Service							
Small Volume	404	110	616,604	$3,912,461	$3,938,974	$26,513	0 7%
Lg Vol/Neg Transp	405	23	2,353,612	$7,682,678	$7,713,308	$30,629	0 4%
Total Interruptible Service		**133**	**2,970,216**	**$11,595,140**	**$11,652,282**	**$57,142**	**0.5%**
Total Gas Sales		**40,827**	**9,788,923**	**$68,841,092**	**$69,722,722**	**$881,629**	**1.3%**
Other Gas Revenues							
Connection Charge				$45,000	$45,000	$0	0 0%
Late Payment Charge				$131,000	$132,473	$1,473	1 1%
Gas Agreement				$26,000	$26,000	$0	0 0%
NSF Check Charge				$1,694	$5,084	$3,390	200 1%
Miscellaneous				$67,000	$67,000	$0	0 0%
Gross Receipts Tax				$979,000	$979,000	$0	0 0%
Other sales				$1,475,000	$1,475,000	$0	0 0%
Meter Calibration Adjustment				$41,000	$41,000	$0	0 0%
Total Other Gas Revenues				**$2,765,694**	**$2,770,557**	**$4,863**	**0.2%**
Total Sales and Other Gas Revenues				**$71,606,786**	**$72,493,279**	**$886,493**	**1.2%**

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Settlement Agreement - Comparison of Option "A" and Class Cost of Service Study Results
(000's)

	(1)	(2)	(3)	(4)	(5)
Customer Class		**Present Revenues**	**Revenue Deficiency Indicated by CCOSS**	**Total Effect Of Option A Rates**	**Difference Between CCOSS Revenue Deficiency and Option A Rates**
Residential	$ increase	$26,361	$3,009	$599	$2,410
	% increase		11 4%	2 3%	9 1%
Commercial	$ increase	$30,885	($1,119)	$226	($1,345)
	% increase		-3 6%	0 7%	-4 4%
Interruptible Service	$ increase	$3,912	($291)	$27	($318)
(Small Volume)	% increase		-7 4%	0 7%	-8 1%
Interruptible Service	$ increase	$7,683	($319)	$31	($350)
(Large Volume)	% increase		-4 2%	0 4%	-4 6%
Other Revenues	$ increase	$2,766		$5	
	% increase				
Total	$ increase	$71,607	$1,280	$886	$394
	% increase		1 8%	1 2%	0 5%

Rate Design - Class Impact by Rate Component

	(1)	(2)	(3)	(4)
			Overall Impacts of Option A Rates	
Customer Class		**Present Revenues**	**Basic Service Charges**	**Distribution Charges**	**Total Effect of All Changes**
Residential	$ increase	$26,361	$1,348	($749)	$599
	% increase		5 1%	-2 8%	2 3%
Commercial	$ increase	$30,885	$442	($217)	$226
	% increase		1 4%	-0 7%	0 7%
Small Interruptible	$ increase	$3,912	$0	$27	$27
	% increase		0 0%	0 7%	0 7%
Large Interruptible	$ increase	$7,683	$0	$31	$31
	% increase		0 0%	0 4%	0 4%
Total	$ increase	$68,841	$1,790	($908)	$882
	% increase		2 6%	-1 3%	1 3%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Settlement Agreement - Comparison of Option "A" and Class Cost of Service Study Results

Firm Sales Service	Present Rates	Option A Rates
Residential		
Basic Service Charge	$5.50 / Month	$8 75 / Month
Distribution Charge	$0.12480 /Therm	$0.10000 /Therm
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0.68199 /Therm	$0.68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Commercial and Industrial - Firm		
Basic Service Charge	$14.00 /Month	$20.00 /Month
Distribution Charge	$0.11280 /Therm	$0.10710 /Therm
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0.68199 /Therm	$0.68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Small Interruptible Service		
Basic Service Charge	$75.00 /Month	$75.00 /Month
Distribution Charge	$0.07310 /Therm	$0.07740 /Therm
Cost of Gas	$0.54166 /Therm	$0.54166 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Large Interruptible Service		
Basic Service Charge	$275.00 /Month	$275.00 /Month
Distribution Charge	$0.04390 /Therm	$0.04632 /Therm
Cost of Gas	$0.54166 /Therm	$0.54166 /Therm
MGP amortization	$0.00368 /Therm	$0 00368 /Therm

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Settlement Agreement Option A Rates

RESIDENTIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option A	Amount	Percent
5	$9 55	$12 68	$3 13	32 7%
10	$13 60	$16 61	$3 00	22 1%
20	$21 71	$24 46	$2 75	12 7%
30	$29 81	$32 32	$2 51	8 4%
40	$37 92	$40 18	$2 26	6 0%
50	$46 02	$48 03	$2 01	4 4%
75	$66 29	$67 68	$1 39	2 1%
100	$86 55	$87 32	$0 77	0 9%
200	$167 59	$165 88	($1 71)	-1 0%
300	$248 64	$244 45	($4 19)	-1 7%
500	$410 73	$401 58	($9 15)	-2 2%

COMMERCIAL & INDUSTRIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option A	Amount	Percent
5	$17 99	$23 96	$5 97	33 2%
50	$53 92	$59 64	$5 72	10 6%
100	$93 85	$99 28	$5 43	5 8%
250	$213 62	$218 19	$4 58	2 1%
500	$413 23	$416 38	$3 15	0 8%
750	$612 85	$614 58	$1 73	0 3%
1000	$812 47	$812 77	$0 30	0 0%
3000	$2,409 40	$2,398 30	($11 10)	-0 5%
5000	$4,006 34	$3,983 84	($22 50)	-0 6%
7500	$6,002 51	$5,965 76	($36 75)	-0 6%
10000	$7,998 68	$7,947 68	($51 00)	-0 6%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Settlement Agreement Option A Rates

SMALL VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option A	Amount	Percent
1,000	$693 44	$697 74	$4 30	0 6%
3,000	$1,930 31	$1,943 21	$12 90	0 7%
5,000	$3,167 19	$3,188 69	$21 50	0 7%
7,500	$4,713 28	$4,745 53	$32 25	0 7%
10,000	$6,259 38	$6,302 38	$43 00	0 7%

LARGE VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option A	Amount	Percent
1,000	$864 24	$866 66	$2 42	0 3%
3,000	$2,042 71	$2,049 97	$7 26	0 4%
5,000	$3,221 19	$3,233 29	$12 10	0 4%
7,500	$4,694 28	$4,712 43	$18 15	0 4%
10,000	$6,167 38	$6,191 58	$24 20	0 4%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test year
Settlement Agreement - Comparison of Option "B" and Class Cost of Service Study Results

	Rate Code	Avg Cust.	Dkt Sales	Revenue		Increase	
				Present	Option B	Amount	%
Firm Service							
Residential	401	34,553	3,018,662	$26,361,011	$26,818,913	$457,902	1 7%
Commercial and Industrial	410	6,141	3,800,045	$30,884,941	$31,110,473	$225,532	0 7%
Total Firm Service		**40,694**	**6,818,707**	**$57,245,953**	**$57,929,387**	**$683,434**	**1.2%**
Interruptible Service							
Small Volume	404	110	616,604	$3,912,461	$3,938,974	$26,513	0 7%
Lg Vol/Neg Transp	405	23	2,353,612	$7,682,678	$7,713,308	$30,629	0 4%
Total Interruptible Service		**133**	**2,970,216**	**$11,595,140**	**$11,652,282**	**$57,142**	**0.5%**
Total Gas Sales		**40,827**	**9,788,923**	**$68,841,092**	**$69,581,669**	**$740,576**	**1.1%**
Other Gas Revenues							
Connection Charge				$45,000	$45,000	$0	0 0%
Late Payment Charge				$131,000	$132,205	$1,205	0 9%
Gas Agreement				$26,000	$26,000	$0	0 0%
NSF Check Charge				$1,694	$5,084	$3,390	200 1%
Miscellaneous				$67,000	$67,000	$0	0 0%
Gross Receipts Tax				$979,000	$979,000	$0	0 0%
Other sales				$1,475,000	$1,475,000	$0	0 0%
Meter Calibration Adjustment				$41,000	$41,000	$0	0 0%
Total Other Gas Revenues				**$2,765,694**	**$2,770,289**	**$4,595**	**0.2%**
Total Sales and Other Gas Revenues				**$71,606,786**	**$72,351,958**	**$745,172**	**1.0%**

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Settlement Agreement - Comparison of Option "B" and Class Cost of Service Study Results
(000's)

	(1)	(2)	(3)	(4)	(5)
Customer Class		**Present Revenues**	**Revenue Deficiency Indicated by CCOSS**	**Total Effect Of Option B Rates**	**Difference Between CCOSS Revenue Deficiency and Option B Rates**
Residential	$ increase	$26,361	$3,009	$458	$2,551
	% increase		11 4%	1 7%	9 7%
Commercial	$ increase	$30,885	($1,119)	$226	($1,345)
	% increase		-3 6%	0 7%	-4 4%
Interruptible Service	$ increase	$3,912	($291)	$27	($318)
(Small Volume)	% increase		-7 4%	0 7%	-8 1%
Interruptible Service	$ increase	$7,683	($319)	$31	($350)
(Large Volume)	% increase		-4 2%	0 4%	-4 6%
Other Revenues	$ increase	$2,766		$5	
	% increase				
Total	$ increase	$71,607	$1,280	$745	$535
	% increase		1 8%	1 0%	0 7%

Rate Design - Class Impact by Rate Component

	(1)	(2)	(3)	(4)
			Overall Impacts of Option B Rates	
Customer Class		**Present Revenues**	**Basic Service Charges**	**Distribution Charges**	**Total Effect of All Changes**
Residential	$ increase	$26,361	$4,225	($3,767)	$458
	% increase		16 0%	-14 3%	1 7%
Commercial	$ increase	$30,885	$442	($217)	$226
	% increase		1 4%	-0 7%	0 7%
Small Interruptible	$ increase	$3,912	$0	$27	$27
	% increase		0 0%	0 7%	0 7%
Large Interruptible	$ increase	$7,683	$0	$31	$31
	% increase		0 0%	0 4%	0 4%
Total	$ increase	$68,841	$4,667	($3,927)	$741
	% increase		6 8%	-5 7%	1 1%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Settlement Agreement - Comparison of Option "B" and Class Cost of Service Study Results

Firm Sales Service	Present Rates	Option B Rates
Residential		
Delivery Services	$5.50 / Month	$15.69 / Month
Distribution Charge	$0.12480 /Therm	
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0.68199 /Therm	$0 68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Commercial and Industrial - Firm		
Basic Service Charge	$14 00 /Month	$20.00 /Month
Distribution Charge	$0.11280 /Therm	$0.10710 /Therm
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0.68199 /Therm	$0.68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Small Interruptible Service		
Basic Service Charge	$75.00 /Month	$75.00 /Month
Distribution Charge	$0.07310 /Therm	$0.07740 /Therm
Cost of Gas	$0 54166 /Therm	$0.54166 /Therm
MGP amortization	$0 00368 /Therm	$0.00368 /Therm
Large Interruptible Service		
Basic Service Charge	$275.00 /Month	$275.00 /Month
Distribution Charge	$0.04390 /Therm	$0.04632 /Therm
Cost of Gas	$0.54166 /Therm	$0 54166 /Therm
MGP amortization	$0 00368 /Therm	$0.00368 /Therm

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Settlement Agreement Option B Rates

RESIDENTIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option B	Amount	Percent
5	$9 55	$19 12	$9 57	100 1%
10	$13 60	$22 55	$8 94	65 7%
20	$21 71	$29 40	$7 69	35 4%
30	$29 81	$36 26	$6 45	21 6%
40	$37 92	$43 12	$5 20	13 7%
50	$46 02	$49 97	$3 95	8 6%
75	$66 29	$67 12	$0 83	1 3%
100	$86 55	$84 26	($2 29)	-2 6%
200	$167 59	$152 82	($14 77)	-8 8%
300	$248 64	$221 39	($27 25)	-11 0%
500	$410 73	$358 52	($52 21)	-12 7%

COMMERCIAL & INDUSTRIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option B	Amount	Percent
5	$17 99	$23 96	$5 97	33 2%
50	$53 92	$59 64	$5 72	10 6%
100	$93 85	$99 28	$5 43	5 8%
250	$213 62	$218 19	$4 58	2 1%
500	$413 23	$416 38	$3 15	0 8%
750	$612 85	$614 58	$1 73	0 3%
1000	$812 47	$812 77	$0 30	0 0%
3000	$2,409 40	$2,398 30	($11 10)	-0 5%
5000	$4,006 34	$3,983 84	($22 50)	-0 6%
7500	$6,002 51	$5,965 76	($36 75)	-0 6%
10000	$7,998 68	$7,947 68	($51 00)	-0 6%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Settlement Agreement Option B Rates

SMALL VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option B	Amount	Percent
1,000	$693 44	$697 74	$4 30	0 6%
3,000	$1,930 31	$1,943 21	$12 90	0 7%
5,000	$3,167 19	$3,188 69	$21 50	0 7%
7,500	$4,713 28	$4,745 53	$32 25	0 7%
10,000	$6,259 38	$6,302 38	$43 00	0 7%

LARGE VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Option B	Amount	Percent
1,000	$864 24	$866 66	$2 42	0 3%
3,000	$2,042 71	$2,049 97	$7.26	0 4%
5,000	$3,221 19	$3,233 29	$12 10	0 4%
7,500	$4,694 28	$4,712 43	$18 15	0 4%
10,000	$6,167 38	$6,191 58	$24 20	0 4%

Northern States Power Co. d/b/a Xcel Energy
Monthly Residential Bills

	(a)	(b)	©	(d)	(e)	(f)	(g)	(h)	(I)
2004 ND Cal Mo. Gas Current Rates	Therms	Customers	Avg use per Mo (Therms)	Basic Service $5 50	Distrib Charge $0 12480	Delivery Services	Wholes Nat Gas Prices	Cost of Gas	Total Bill
Jul	41,616	34,422	12 1	$5 50	$1 51	$7.01	$0 65089	$7 87	$14.88
Aug	53,512	34,705	15 4	$5 50	$1.92	$7.42	$0 64103	$9.88	$17 31
Sep	76,726	34,875	22 0	$5 50	$2 75	$8.25	$0 58062	$12 77	$21 02
Oct	170,898	35,164	48 6	$5 50	$6 07	$11.57	$0 59503	$28 92	$40.48
Nov	292,876	35,483	82 5	$5 50	$10 30	$15.80	$0 88900	$73 38	$89 18
Dec	485,995	35,731	136 0	$5 50	$16 97	$22.47	$0 86392	$117.51	$139 98
Jan	642,485	34,541	186 0	$5 50	$23 21	$28.71	$0 72697	$135 22	$163 93
Feb	470,480	34,530	136 3	$5.50	$17.00	$22 50	$0 71552	$97.49	$120 00
Mar	357,344	34,618	103 2	$5.50	$12 88	$18 38	$0 66400	$68 54	$86 92
Apr	207,710	34,506	60.2	$5.50	$7 51	$13 01	$0 59795	$35.99	$49 01
May	119,775	34,430	34 8	$5 50	$4 34	$9.84	$0 63022	$21 92	$31 77
Jun	55,957	34,400	16 3	$5 50	$2.03	$7.53	$0 69293	$11 27	$18 80
	2,975,374	34,784	71 1		Avg	$14.38		$51 73	$66 11

2004 ND Cal Mo. Gas Settlement Option A	Therms	Customers	Avg use per Mo (Therms)	Basic Service $8 75	Distrib Charge $0 10000	Delivery Services	Wholes Nat Gas Prices	Cost of Gas	Total Bill
Jul	41,616	34,422	12.1	$8.75	$1 21	$9 96	$0 65089	$7 87	$17.83
Aug	53,512	34,705	15 4	$8.75	$1 54	$10.29	$0 64103	$9 88	$20 18
Sep	76,726	34,875	22 0	$8.75	$2.20	$10 95	$0 58062	$12 77	$23.72
Oct	170,898	35,164	48 6	$8 75	$4 86	$13 61	$0 59503	$28.92	$42 53
Nov	292,876	35,483	82.5	$8 75	$8 25	$17 00	$0 88900	$73.38	$90.38
Dec	485,995	35,731	136 0	$8 75	$13 60	$22.35	$0 86392	$117 51	$139.86
Jan	642,485	34,541	186 0	$8.75	$18 60	$27.35	$0 72697	$135 22	$162 57
Feb	470,480	34,530	136 3	$8.75	$13 63	$22.38	$0 71552	$97 49	$119 87
Mar	357,344	34,618	103.2	$8 75	$10 32	$19.07	$0 66400	$68.54	$87 61
Apr	207,710	34,506	60.2	$8 75	$6 02	$14 77	$0 59795	$35 99	$50 76
May	119,775	34,430	34 8	$8 75	$3.48	$12 23	$0 63022	$21 92	$34 15
Jun	55,957	34,400	16.3	$8 75	$1 63	$10 38	$0 69293	$11 27	$21 65
	2,975,374	34,784	71 1		Avg	$15.86		$51 73	$67 59

2004 ND Cal Mo. Gas Settlement Option B	Therms	Customers	Avg use per Mo (Therms)	Basic Service $15 69	Distrib Charge $0 00000	Delivery Services	Wholes Nat Gas Prices	Cost of Gas	Total Bill
Jul	41,616	34,422	12 1	$15.69	$0.00	$15.69	$0 65089	$7.87	$23 56
Aug	53,512	34,705	15 4	$15 69	$0 00	$15 69	$0 64103	$9.88	$25.57
Sep	76,726	34,875	22 0	$15 69	$0 00	$15.69	$0 58062	$12.77	$28 46
Oct	170,898	35,164	48 6	$15.69	$0 00	$15.69	$0 59503	$28 92	$44.61
Nov	292,876	35,483	82 5	$15.69	$0 00	$15 69	$0 88900	$73 38	$89 07
Dec	485,995	35,731	136 0	$15.69	$0.00	$15 69	$0 86392	$117 51	$133 20
Jan	642,485	34,541	186.0	$15 69	$0.00	$15 69	$0 72697	$135.22	$150.91
Feb	470,480	34,530	136 3	$15.69	$0 00	$15.69	$0 71552	$97 49	$113.18
Mar	357,344	34,618	103 2	$15.69	$0 00	$15.69	$0 66400	$68 54	$84 23
Apr	207,710	34,506	60 2	$15 69	$0 00	$15.69	$0 59795	$35.99	$51 68
May	119,775	34,430	34.8	$15 69	$0.00	$15.69	$0 63022	$21 92	$37 61
Jun	55,957	34,400	16 3	$15 69	$0.00	$15 69	$0 69293	$11 27	$26 96
	2,975,374	34,784	71 1		Avg	$15 69		$51 73	$67 42

Memorandum

RECEIVED
MAR - 4 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

To: Illona Jeffcoat-Sacco, Executive Secretary

From: Advocacy Staff

Date: March 4, 2005

Re: **Staff Support for Settlement Agreement**
Case No. PU-04-578

Executive Summary

On June 27, 2001, in Case No. PU-400-00-521, the commission ordered a rate increase of $500,000 for Xcel Energy's North Dakota gas operations based on an 11.5% return on common equity. Since then, the company has been earning returns on its equity of less than 9%.

On November 4, 2004, Xcel Energy filed for a rate increase of $1.28 million using a 2004 test year and an 11.5% return on equity.

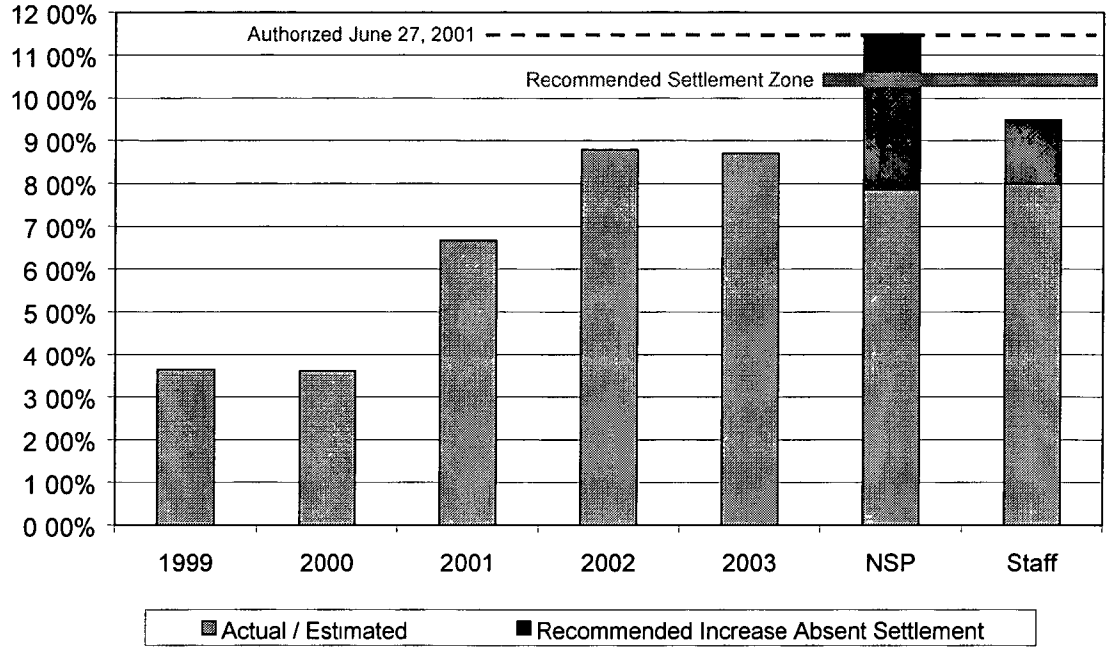
A settlement was filed on February 17, 2004, giving the commission two options by which the parties can agree. Option A provides for a rate increase of $887,000 using the traditional two-pronged residential delivery service charge including a fixed rate plus a volumetric charge. Option B provides for an increase of $745,000 which combines both residential delivery service charges into one fixed rate of $15.69 per month. Staff favors adoption of Option B for billing simplicity and revenue stability reasons.

In staff's opinion, Option A will provide Xcel Energy with the initial opportunity to earn 10.64% on its equity invested in North Dakota gas operations. Option B will provide Xcel Energy with an opportunity to earn 10.22%. Xcel Energy is agreeable to a smaller increase under Option B because it would eliminate the loss of margins due to the trend of a declining use per residential customer.

If this case is not settled, staff will likely counter the company's proposed return on common equity of 11.5% by arguing that a 9.5% return is reasonable. Staff is agreeable to slightly higher returns for settlement purposes given the uncertain outcome of a contested hearing

Following is an illustration of actual and projected earnings levels and the two settlement options discussed above.

Xcel Energy
North Dakota Gas Operations
Return on Equity



The staff understands the difficulty of approving rate increases when the commodity price of natural gas is high. Yet, the cost of natural gas is not controlled by Xcel Energy nor does the company benefit from high natural gas prices. The proposed rate increase is for increased costs to distribute the natural gas to end users, and the recommended rate design (Option B) will, among other things, help to make this more clear to customers.

Similarly, staff recognizes that the company has a fiduciary responsibility to its stockholders to earn a reasonable return on its investment in North Dakota--even when the commodity price of natural gas is high. The timing for a rate increase is unfortunate. However, based on historical earnings and staff investigations in this proceeding, staff concludes a rate increase is appropriate.

Major Settlement and Policy Issues

Viking Gas Transmission Company

On March 23, 1994, Case No. PU-400-93-534, the commission denied NSP's (Xcel Energy) request to recover additional revenues through its purchase gas adjustment related to the premium it paid above book value for the acquisition of Viking Gas Transmission Company. However, the commission agreed to a 15 year amortization without carrying costs and that it would re-examine the matter in Xcel's next rate case. The commission staff argued, among other things, that recovery should not be allowed unless customers also share in any gain realized from the subsequent selling of Viking.

On August 7, 1996, the commission ordered (Case No. PU-400-95-559) a rate reduction of $486,000 and NSP began including North Dakota's share of the amortization of the Viking acquisition premium in its purchase gas adjustment.

On November 11, 2002, Xcel Energy sold Viking to Northern Border.

Based on information provided by Xcel Energy, purchasing Viking enabled it to negotiate favorable transmission contracts with Northern Natural Gas shortly after acquiring Viking. The acquisition of Viking provided Xcel with the ability to bypass Northern Natural Gas by expanding its use of the Viking pipeline. Xcel quantifies that the resulting contract discounts have resulted in savings of $4,550,380 to date and still remain in effect even after selling Viking to Northern Border. The total cost of the premium amortization to North Dakota consumers totaled $1,509,824. Xcel's contract discounts indicate that the pipeline acquisition was beneficial to consumers in North Dakota.

With regard to any gains realized on the sale of Viking, this Settlement Agreement does not address the issue. Staff believes that the legal challenge of arguing for a share of the gain would be very difficult since the transmission company is a non-jurisdictional asset.

Cost of Capital Adjustment

In determining a reasonable settlement, staff made the assumption to continue with the capital structure as reflected in Xcel's annual financial reports filed with the commission.

Following is a comparison of Xcel's proposed cost of capital calculation and staff's estimated cost of capital allowed under Options A and B of the settlement.

2004 NSP:			
Debt	49 76%	7.34%	3 65%
Common Equity	50.24%	11.50%	5 78%
Total	100 00%		9.43%
Option A:			
Debt	52.50%	7 34%	3 85%
Common Equity	47 50%	10.64%	5 06%
Total	100.00%		8.91%
Option B:			
Debt	52.50%	7 34%	3.85%
Common Equity	47.50%	10.22%	4 85%
Total	100 00%		8 71%

MGP Clean-up Costs

As you may recall from the last rate case, the company incurred an unexpected expense of nearly $3 million to clean-up its Grand Forks manufactured gas plant site. The last rate case settlement approved by the commission ordered an 8 year amortization of these costs beginning September 1, 2001, with no rate base treatment of the unamortized balance.

In determining a reasonable settlement for this proceeding, staff excluded the unamortized manufactured gas plant clean-up costs from rate base totaling $1.8 million. Part of the reason for not allowing carrying costs in the last rate case was to provide an incentive to the company to try and recover as much as it could through insurance recoveries. Even though Xcel Energy has not been able to secure any additional insurance recoveries for the clean-up, staff is not convinced that rate base recognition is appropriate.

Depreciation

Depreciation studies are extremely costly and time consuming to monitor and oversee. The staff and the commission have recognized the value of the annual and more detailed 5-year depreciation reviews conducted by the Minnesota Public Utilities Commission. That commission, through its Department of Commerce, has more resources to conduct rigorous reviews of depreciation rates.

In the past, the commission has been comfortable with the depreciation rates developed through that process for both Otter Tail Power Company and Xcel Energy. It makes sense to continue to avail ourselves of the

work performed by the Minnesota Commission and to utilize the same rates so that Xcel does not have the added administrative cost of keeping separate depreciation records for both states.

Hedging with Financial Instruments

Beginning in 2000, the high cost of natural gas has been a customer concern as well as a national concern. Accordingly, Xcel Energy began to more fully utilize financial instruments such as futures and options to minimize the price volatility of natural gas. Hedging via financial instruments alone accounts for almost $1 million of Xcel Energy's investment in North Dakota gas operations.

These financial instruments allow Xcel Energy to take a position in the market for a fixed delivery price sometime in the future. If prices subsequently increase, a gain is recognized. Conversely, if prices subsequently decrease, a loss is recognized for the difference between the agreed to price and the eventual market price. The gains and losses of these instruments are netted against the market price to ensure a more stable price of gas for Xcel Energy's consumers.

The commission's rules allow Xcel Energy to flow through the gains and losses realized through the use of financial instruments through the purchase gas adjustment. Staff agrees with the commission's direction on flowing through costs associated with financial instruments and agrees that these kinds of steps are appropriate to try and mitigate the fluctuating natural gas prices Staff therefore accepts the higher rate base level related to the company's hedging activities.

Fuel Stocks

Hedging against price volatility can also occur by securing storage facilities. Storage facilities enable the company to buy when natural gas prices are low and then store for distribution during high cost periods. The company secured an additional 1.4 Bcf of storage (system wide) or a 16% increase in storage capabilities in 2004 compared to 2003. The additional storage capacity and higher natural gas prices have resulted in increased carrying cost related to fuel inventory. Again, the staff is agreeable to minimizing the price volatility of natural gas and accepts the higher level of fuel stock included in rate base.

As a result of the increased use of financial instruments and gas storage inventories along with the normal peak shaving programs, Xcel Energy is able to hedge about 55% of its heating season natural gas flows.

Class Cost of Service Study

Xcel filed an embedded Class Cost of Service Study (CCOS) that included a minimum distribution system methodology for classifying 69.3% of the distribution main expense as customer-related. This method increases the costs to be recovered from customer charges. Further, because customer related costs are allocated among the classes according to number of customers, the costs allocated to the residential class would also be increased. Xcel also used an "average and excess" method for allocating transmission plant and regulator station costs along with the remaining 30.7% of distribution main costs. Such a method results in the interruptible classes being spared responsibility for costs related to peak design day requirements.

Staff requested a rerun of the CCOS with no minimum distribution system and with 75% of transmission plant, regulator stations and distribution main expense allocated to the customer classes according to class average usage. The remaining 25% was allocated according to the difference between class average and design-day usage.

A comparison of these two CCOS runs indicates that the interim residential customer charge of $5.83 is set below cost and the residential customer class is providing a smaller return than are the other classes.

	% ROR		Monthly Customer Cost	
Customer Class	Xcel	Staff	Xcel	Staff
Residential	2.4%	4.3%	$ 17.99	$ 11.91
Firm Commercial	14 3%	10.1%	$ 31.89	$ 25.80
Small Interruptible	32.4%	16.8%	$ 71.30	$ 65.22
Large Interruptible	20.2%	9.9%	$138.47	$132.38

Rate Design

Based on the above CCOS comparison, the parties were able to agree to customer class increases that move the customer classes towards equalized returns while minimizing billing impacts and exposures to competition from alternative fuels.

Staff had several discussions with the company regarding its "partial decoupling" mechanism but was unable to reach an agreement. Staff was willing to support an alternative weather normalization adjustment similar

to what was approved for MDU, but Xcel was not able to implement on a real time basis. Without real time information and billing, a weather normalization adjustment becomes even more confusing to customers.

Absent real time capabilities, discussions turned towards Xcel's alternative proposal for a $14.00 residential monthly customer charge instead of the proposed "partial decoupling" mechanism. It was apparent that at $14.00 we were close to eliminating the residential distribution delivery charge.

At first, staff was hesitant about such a significant change from traditional rate design and past commission policy. However, there are several advantages to a flat rate distribution charge. The timing for adopting such an approach is more palatable than ever given that the distribution costs are so small in comparison to the total bill. Customers have also become accustomed to paying flat fees for internet service, local telephone, cable TV, and other services. Most of the customer complaints received by the commission have been about the commodity cost of gas—not the distribution charges. As a result, Option B was negotiated and included in the settlement for commission consideration.

Option B
Staff believes the primary benefits of Option B are billing simplicity and revenue stability. With a flat rate distribution charge it would be much easier for customers to see and understand that only $15.69 of their heating bill is retained by Xcel and that the rest goes to the unregulated wholesale suppliers of natural gas. Additionally, the need for complicated and confusing weather normalization and/or "partial decoupling" billing adjustments would be eliminated because the company would no longer be subject to risk from abnormal weather or trends of declining customer usage.

Consider the following quote of an e-mail received last month from a consumer frustrated by MDU's weather normalization adjustment:

> *"I would like to know how come you let MDU keep ripping off the people of N.Dak I received my bill and the gas is the same price as last month and I have been watching and the gas has went down some. and if you try to cut back they still have an extra charge they can use what a sham. I know they have the money and help in your reelections but I think it is time to look out for the people of N Dak Thank You"* **emphasis added**

Staff sees two primary drawbacks with Option B: 1) A higher percentage impact on low usage customers and 2) A potential adverse customer reaction to a large customer charge increase.

Xcel reports that approximately 1,300 customers (out of 41,000 North Dakota gas customers) do not use natural gas for space heating. If we assume an average usage of approximately 30 therms per month, then these customers would see an increase of about $6.45 per month.

Please note that there is some cost basis for this because many of the non-space heating customers are thought to heat their premises with electricity under the dual-fuel heating rates of neighboring electric cooperatives. When customers heat with natural gas only during electric interruptions they are contributing to the natural gas system peak design day requirement without contributing a fair share to cover costs under the traditional rate design approach.

The second drawback of Option B arises when customers do not understand customer charges and want to be billed only for what they consume. Staff believes that adverse customer reactions will be minimized by the summer implementation date and by messages in the bill explaining that the volumetric Distribution Charge and the fixed Basic Service Charge have been combined into a single Delivery Services charge.

Staff believes the benefits of Option B outweigh the drawbacks and recommends the commission accept Option B of the Settlement Agreement. Staff realizes that Option B represents a change from traditional regulatory practice and past commission precedent. Therefore, a more traditional rate design was negotiated and included in the Settlement Agreement as Option A.

Option A

Option A does not adopt Xcel's proposed "partial decoupling" adjustment and therefore provides a higher residential revenue requirement than Option B. The $8 75 residential

customer charge is $0.25 higher than originally proposed, but still less than the $0.31 per day recently approved for MDU and less than customer related costs under either staff or company CCOS calculations.

Miscellaneous Rate Design Changes
Xcel's Electric customers are assessed a $15.00 charge for non-sufficient funds checks. Many of Xcel's customers are combination electric and gas customers and write one check for one bill for both services. Therefore, it appears reasonable that the electric and gas returned check charges be the same. Staff supports the proposed change to increase these charges from $5.00 to $15.00.

Staff believes the changes proposed for Xcel's winter construction charges would better reflect costs incurred.

Staff does not object to the remaining proposed miscellaneous tariff changes explained in the prepared testimony of Mr. Nicholas Paluck filed December 3, 2004.

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INVOICE

DATE: 3/1/2005
INVOICE # 3672

Bill To:

ND Public Service Commission
600 E. Boulevard Avenue, Dept 408
Bismarck, ND 58505-0480

Attn. Sandi Scott

For: Event(s) on IVN
02/07/05
7 00-8 50pm

DESCRIPTION	HOURS	RATE	AMOUNT
Telephone Line Charge.	1.83	80 00	$ 146 40
Technical Charge $10/hr/site	2	20 00	40.00
Sites			
Host - Bismarck Public Library, UND, NDSU			
Administrative Fee per event		50 00	
Site Fee per event		25 00	
Long Distance Line Charge		80 00	
		SUBTOTAL	$ 186 40
			-
		OTHER	-
		TOTAL	$ 186 40

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64 **PU-04-578** Pages 1

Invoice for 2/7/05 Public Input Session

by ND Interactive Video Network

Xcel Energy™

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(701) 241-8632
dave sederquist@xcelenergy com

February 16, 2005

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ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Northern States Power Company d/b/a Xcel Energy Notice of Change in Rates for Natural Gas Service (Case No. PU-400-04-578)

Dear Ms. Jeffcoat-Sacco:

Enclosed herewith is a Settlement Agreement reached between Xcel Energy and the Commission advocacy Staff pertaining to the Company's Natural Gas general rate increase application, Case No. PU-400-04-578.

The Company believes Settlement Agreement and the rate options described in the Settlement Agreement would serve the public interest because they:

- allow the Company to recover its reasonable cost of providing natural gas service in North Dakota while ensuring that customers pay no more than is required to do so;
- reduce existing inter- and intra-class subsidies while minimizing the percentage rate increase to any single customer class,
- do not unreasonably discriminate between the Company's customers or customer classes;
- improve economic signals by aligning fixed monthly charges more closely with the costs incurred to serve; and
- do not violate any other Commission laws or rules.

In addition, resolving the rate case by settlement will allow the Commission to efficiently use its available resources in 2005.

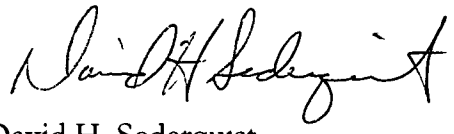
The Settlement Agreement provides two rate options for the Commission to consider. The Settlement Agreement leaves it to the Commission to select the rate option and resulting overall rate increase level. The final gas rates set forth in the selected option would be placed into effect June 1, 2005, and there would be no refunds of the interim rate increase placed into effect on January 1, 2005.

63 PU-04-578 Pages 2
Cover letter re Settlement Agreement
by Northern States Power Company by
02/17/2005 C Comm Legal PUD (4) Mike ALJ

The Company respectfully requests that the Commission promptly schedule an informal hearing and conduct the necessary working sessions to review the Settlement Agreement and issue an order approving it, including the associated rate option selection. The Company hopes that the time and expense of filing additional testimony and conducting formal hearings in this matter can be avoided through the approval of this Settlement Agreement.

Please contact me if you have any other questions or comments.

Sincerely,



David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Co. d/b/a Xcel Energy

Enclosures

Cc: Bill Binek, Commission Chief Counsel
Jerry Lein, Commission Advocacy Staff

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EXECUTIVE SECRETARY

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company /d/b/a Xcel Energy
Natural Gas Rates

Case No. PU-400-04-578

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 17th day of February, 2005, by and between the North Dakota Public Service Commission Staff ("Staff") and Northern States Power Company d/b/a Xcel Energy, a Minnesota corporation ("Xcel Energy" or "the Company"), (collectively, the "Parties"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in just and reasonable rates for the Company's retail natural gas operations in North Dakota.

PROCEDURAL HISTORY

1 On November 2, 2004, Xcel Energy filed a Notice of Change in Rates for Natural Gas Service with the North Dakota Public Service Commission ("Commission"), based on a 2004 test year, to become effective January 1, 2005. The Notice proposed an increase in natural gas retail and miscellaneous revenues of $1,280,000, or about 1.8 percent overall. Xcel Energy proposed to increase residential bills approximately 4 6 percent through a $3.00 increase in the monthly Basic Service Charge coupled with a slight reduction in the volumetric Distribution charge The Company proposed to increase Commercial - Interruptible service revenues by 0.5 percent Other tariff changes included increases in Returned Check charges and a refinement of winter construction charges. The Company also proposed a "Partial Decoupling Rider" designed to recover volumetrically charged distribution revenues lost to the ongoing trend of declining use per customer Filed with the Notice were revised tariffs, exhibits, and supporting statements

2 Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase was for $741,000 or 1.1

percent overall, to be effective January 1, 2005 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C 49-05-06

3. On December 2, 2004, Xcel Energy filed direct testimony in support of its Notice of Change in Natural Gas Rates

4 On November 18, 2004, the Commission issued an order suspending Xcel Energy's general rate increase application and set the matter for investigation and hearing.

5 On November 23, 2004, Commission advisory staff filed comments stating that Xcel Energy's interim rate petition complied with N.D C.C 49-05-06. On December 1, 2004, the Commission issued an order allowing interim rates as proposed by the Company to be placed into effect January 1, 2005, subject to refund.

6 On December 15, 2004, the Commission issued a Notice of Hearing, Notice of Public Input Session, and Notice of Intervention Deadline ("Commission Notice") which set forth the following issues to be considered in this case.

- What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
- What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
- Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
- Other relevant information or proposals concerning the proceeding.

7 On February 7, 2005, the Commission conducted a public input session as provided in the Commission Notice. The session utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, and Bismarck.

8 Under the Commission Notice the deadline for filing a Petition to Intervene was January 31, 2005 No party filed such a petition in this proceeding.

9. Discovery requests were served on Xcel Energy by the advocacy Staff and were responded to by the Company

10. Various settlement discussions were held between the Company and the Commission advocacy staff during December 2004, January 2005, and February 2005 As a result of those discussions, the Parties reached this Settlement Agreement.

11 The administrative record supports the Settlement Agreement. Accordingly, the Parties jointly recommend the Commission issue an Order approving this Settlement Agreement, including either of the two options contained therein, without conditions or modifications.

TERMS OF SETTLEMENT AGREEMENT

I. RATE OPTIONS

The Parties agree to rate Options A and B discussed below and summarized on Schedules A, B, and C attached to this Settlement The parties recommend the Commission select and approve the rate option of the Commission's choice:

Option A: Traditional Two-Part Residential Delivery Service Rates

1 **Revenue Increase**.

The Parties agree to, and recommend the Commission approve, a net increase in Xcel Energy's natural gas rates for retail customers in North Dakota to yield an annual retail sales and miscellaneous revenue increase of approximately $887,000, or 1.2%, effective for service rendered on or after June 1, 2005. The Company shall file compliance tariff pages setting forth the revised gas rates and tariffs provided by this Settlement Agreement rate option at least 30 days prior to the effective date

2 **Revenue Apportionment**

The Parties agree to, and recommend the Commission approve, an overall increase in total residential test year revenues of approximately 2 3 percent, a 0 7 percent increase to commercial firm service revenues, and a 0 5 percent overall increase in commercial interruptible service revenues, as shown on Schedule A

3 **Rate Design**

The Parties agree to, and recommend the Commission approve, increasing the residential and commercial firm service monthly Basic Service Charge and decreasing the corresponding volumetric class Distribution Charge as specified on Schedule C The Parties also agree to, and recommend the Commission approve, increases to the commercial interruptible service Distribution Charges, also shown on Schedule C

4 **Partial Decoupling Rider (Declining Use Per Customer Recovery)**

The Parties agree to defer consideration of the Company's proposed Partial Decoupling Rider (the declining residential use per customer recovery mechanism) to a future rate application

Option B: Single Fixed Residential Delivery Services Rate

1 **Revenue Increase**

The Parties agree to, and recommend the Commission approve, a net increase in Xcel Energy's natural gas rates for retail customers in North Dakota to yield an annual retail sales and miscellaneous revenue increase of approximately $745,000, or 1 1%, effective for service rendered on or after June 1, 2005 The Company shall file compliance tariff pages setting forth the revised gas rates and tariffs provided by this Settlement Agreement rate option at least 30 days prior to the effective date

This reflects an overall retail revenue increase approximately equal to the level currently being recovered by the company in interim rates plus an

estimated $3,400 of increased returned check charges This lower overall revenue increase (compared to Option A) is acceptable to the Company because declining use per customer trends would no longer adversely impact residential revenues previously collected through volumetric charges

2 **Revenue Apportionment**

The Parties agree to an overall increase in total residential test year revenues of approximately 1 7 percent All other customer classes would experience revenue increases equal to that agreed to under Option B (and summarized on Schedule B)

3 **Rate Design**

The Parties agree to, and recommend the Commission approve, replace the existing residential monthly Basic Service Charge and the residential volumetric Distribution Charge with a flat monthly Delivery Services Charge of $15 69, as shown on Schedule C Rates for commercial Firm and Interruptible service would be the same as provided in rate Option A

4 **Partial Decoupling Rider (Declining Use Per Customer Recovery)**

The parties agree that the Partial Decoupling Rider proposed in the Application would be unnecessary under Option B because residential delivery revenues would be, by definition, decoupled from customer usage

II. TERMS COMMON TO EITHER RATE OPTION

1 **Rate Base**

For purposes of determining the overall revenue requirement, the Parties agree to a test year average rate base amount of $42,398,000

2 **NSF Check Charges**

The Parties agree to, and recommend the Commission approve, a $15 per check charge for checks returned due to non-sufficient funds ("NSF") This is the same amount as the currently effective NSF charge levied by the

Company to electric customers under its North Dakota Electric Rate Book tariffs

3 **Winter Construction Charges**

The Parties agree to, and recommend the Commission approve, the modifications to winter construction charges as identified on Schedule 3, page 29 (Tariff Section 6, Sheet 19) of the rate Application

4 **Disconnect/Reconnect Charges**

The Parties agree that Xcel Energy may need to revise its natural gas tariffs to discourage customers from "gaming" the existing natural gas rate structure to avoid payment of fixed monthly charges (either the residential Basic Service Charge under Rate Option A or the residential Delivery Services Charge under Rate Option B) This "gaming" occurs primarily when customers regularly request Xcel Energy to disconnect their natural gas service prior to warm weather months and then place a reconnection order prior to the next heating season Such "gaming" both reduces the Company's recovery of fixed distribution costs and increases operating costs for disconnection and reconnection The Company's current natural gas tariffs do not contemplate and adequately recover the costs of these types of service requests The Parties agree that the Company shall submit, by April 1, 2005, a miscellaneous tariff filing to establish disconnection/reconnection charges and tariffs similar to those currently in effect for natural gas customers of Montana-Dakota Utilities

5 **Interim Rates**

The parties agree the final rates effective June 1, 2005 under both rate Options A and B of this Settlement Agreement will generate increased revenues equal to or exceeding the increase collected by the Company under the interim rates implemented January 1, 2005 The parties agree the interim rates will remain in effect for all customer classes for the period January 1, 2005 to May 31, 2005, and no interim rate refunds will be issued

III. OTHER TERMS AND CONDITIONS

1 **Basis of Settlement** It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission The Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding

2 **Effect of the Settlement Negotiations** It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or otherwise

3 **Applicability and Scope** This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding

4 **Effective Date** This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in Section I of Terms of Settlement Agreement

5 **Modification** If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if any party files a letter with the Commission with three (3) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party

Dated this 15th day of February 2005.

Northern States Power Company d/b/a Xcel Energy

By: _____

Vice President, Northern States Power

Dated this 17th day of February, 2005.

Northern Dakota Public Service Commission Staff

By: _____

Chief Counsel

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Revenue Apportionment (Case No. PU-400-04-578)

Option A - Traditional Two-Part Residential Delivery Rate

Customer	Previous Revenues	Interim Revenues	Interim Increase	%	Settlement Revenues	Increase over Previous	%	Increase over Interim	%
Residential	$26,361,011	$26,718,808	$357,797	1 4%	$26,959,966	$598,955	2 3%	$241,158	0 9%
Commercial	$30,884,941	$31,197,667	$312,726	1 0%	$31,110,473	$225,532	0 7%	-$87,194	-0 3%
Total Firm	$57,245,953	$57,916,475	$670,522	1 2%	$58,070,439	$824,486	1 4%	$153,964	0 3%
Sm Comm	$3,912,461	$3,944,778	$32,317	0 8%	$3,938,974	$26,513	0 7%	-$5,804	-0 1%
Lg Indust	$7,682,678	$7,719,432	$36,754	0 5%	$7,713,308	$30,630	0 4%	-$6,124	-0 1%
Total Interruptible	$11,595,140	$11,664,210	$69,070	0 6%	$11,652,282	$57,142	0 5%	-$11,928	-0 1%
Total Retail	$68,841,092	$69,580,685	$739,593	1 1%	$69,722,721	$881,629	1 3%	$142,036	0 2%
Misc Tariffs	$2,765,694	$2,767,101	$1,407	0 1%	$2,770,762	$5,068	0 2%	$3,661	0 1%
Grand Total	$71,606,786	$72,347,786	$741,000	1 0%	$72,493,483	$886,697	1 2%	$145,697	0 2%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Revenue Apportionment (Case No. PU-400-04-578)

Option B - Single Fixed Residential Delivery Rate

Customer	Previous Revenues	Interim Revenues	Interim Increase	%	Settlement Revenues	Increase over Previous	%	Increase over Interim	%
Residential	$26,361,011	$26,718,808	$357,797	1 4%	$26,818,913	$457,902	1 7%	$100,105	0 4%
Commercial	$30,884,941	$31,197,667	$312,726	1 0%	$31,110,473	$225,532	0 7%	-$87,194	-0 3%
Total Firm	$57,245,953	$57,916,475	$670,522	1 2%	$57,929,386	$683,433	1 2%	$12,911	0 0%
Sm Comm	$3,912,461	$3,944,778	$32,317	0 8%	$3,938,974	$26,513	0 7%	-$5,804	-0 1%
Lg Indust	$7,682,678	$7,719,432	$36,754	0 5%	$7,713,308	$30,630	0 4%	-$6,124	-0 1%
Total Interruptible	$11,595,140	$11,664,210	$69,070	0 6%	$11,652,282	$57,142	0 5%	-$11,928	-0 1%
Total Retail	$68,841,092	$69,580,685	$739,593	1 1%	$69,581,668	$740,576	1 1%	$983	0 0%
Misc Tariffs	$2,765,694	$2,767,101	$1,407	0 1%	$2,770,492	$4,798	0 2%	$3,391	0 1%
Grand Total	$71,606,786	$72,347,786	$741,000	1 0%	$72,352,160	$745,374	1 0%	$4,374	0 0%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Settlement Agreement Rate Summary (Case No PU-400-04-578)

	Previous Rates	Interim Rates	Settlement Agreement Option A Residential Two-Part Rate	Settlement Agreement Option B Residential Single Fixed Rate
Residential				
Basic Service Charge (per month)	$5 50	$5 83	$8 75	
Distribution Charge (per therm)	$0 12480	$0 13212	$0 10000	
Delivery Services (per month)				$15 68
Commercial Firm				
Basic Service Charge (per month)	$14 00	$14 83	$20 00	$20 00
Distribution Charge (per therm)	$0 11280	$0 11942	$0 10710	$0 10710
Small Interruptible				
Basic Service Charge (per month)	$75 00	$79 39	$75 00	$75 00
Distribution Charge (per therm)	$0 07310	$0 07740	$0 07740	$0 07740
Large Interruptible				
Basic Service Charge (per month)	$275 00	$291 07	$275 00	$275 00
Distribution Charge (per therm)	$0 04390	$0 04647	$0 04632	$0 04632

North Dakota Newspaper Association
1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

INVOICE

Order **20134-05021PP0** Invoice # **50981**

February 9, 2005

Advertiser **Public Utilities Division**

P O #:

Amount Due	**$468.88**
Amount Paid	

Attn: PATRICK J. FAHN
PUBLIC SERVICE COMMISSION
600 E. BOULEVARD AVE.
STATE CAPITOL
BISMARCK, ND 58505

Voice 701-328-4076

Please detach and return this portion with your payment

Public Utilities Division Invoice # 20134-05021PP0-50981

Ad Size	*Rate Type*	*Rate*	*Total*	*Discount*	*(%)*	*Caption*	*Page*	*Run Date*
Fargo, The Forum (Fargo ND)								
8 00	SAU SU	58 61	468 88	0 00		Natural Gas Rates		02/06/05

Gross Advertising	468 88	Total Misc	0 00	Amount Paid	0 00
Agency Discount		Tax	0 00	Adjustments	0.00
Other Discount	0 00	Total Billed	468 88	Payment Date	
Service Charge	0 00	Unbilled	0 00	Balance Due	468 88

61 **PU-04-578** Pages 1

Invoice for Display ad in the Fargo Forum

by North Dakota Advertising Service, Inc

02/10/2005 C Comm Legal PUD (4) Mike ALJ

Associated Press

MA' ILLE, Mo – Jeffery Lotsha.. flossed regularly. He brushed faithfully, sometimes four or five times in a day.

All that care makes his condition seem incomprehensible – at the age of just 33, Lotshaw's grin is toothless. His teeth all broke apart, tarnished with yellow and black.

"Before I started doing meth, I didn't have a cavity in my head," said Lotshaw, imprisoned on drug charges at Missouri's Maryville Treatment Center.

The growing use of highly addictive methamphetamine throughout the country is creating a prominent scar on an increasing number of users – rotting, brittle teeth that seem to crumble from their mouths.

Methamphetamine can be made with a horrid mix of substances, including over-the-counter cold medicine, fertilizer, battery acid and hydrogen peroxide.

Together, the chemicals reduce a user's saliva, which neutralizes acids and physically clears food from the teeth, said Dr. Eric Curtis, an Arizona-based spokesman for the Academy of General Dentistry.

"When the saliva isn't flowing, the bacteria build up a lot faster," said Dr. Darrell Morton, an Atlanta dentist.

Meth users also may neglect their teeth, or moisten their dry mouths with high-sugar drinks, and anxiety caused by the drug prompts th[e] to grind their teeth, which spe[e]ds decay.

The problem is particularly noticeable among inmates, whose oral problems have some prison systems struggling to provide dental care.

"They're rotting teeth, missing teeth, rotting way into the gums," said Kathy Bachmeier, the head of medical services for North Dakota's prisons. "It's ugly."

There are no statistics on "meth mouth" – as the condition has come to be known – because addicts are sometimes reluctant to admit their drug use and because it is difficult to distinguish between damage done by bad dental hygiene and that caused by narcotics. But there are signs it is on the rise around the country.

The head of the company in charge of dental care for Missouri inmates says he is seeing teeth rotted by meth use nearly every day. In North Dakota, the number of days a dentist was serving inmates jumped from 50 in 2000 to 78 in 2004. And the tab for inmates' dental care in Minnesota rose from $1.2 million five years ago to about $2 million last year.

"There are more and more urgent care needs, which pushes back routine care like cleanings," said Nanette Schroeder, director of health services for Minnesota's Corrections Department. "They're seeing just worse mouths, generally."



TAILGAT[E]
SP[O]
1322 Main A

Lunch Bu[ffet]
$4[.99]
All you can eat!

Monday Wings & Pizza | Tuesday Roast Pork | Burger

One coupon per person per visit. E[xpires]

W

If you ha[ve]
for it, se[e]


Dr. Terry Dwe[rs]
North Dakota State He[alth]

Natural Gas Rates
Your Opportunity To Be Heard

The North Dakota Public Service Commission invites you to a PUBLIC INPUT SESSION on the application of NSP (d/b/a Xcel Energy) to increase natural gas rates.

WHEN: February 7, 2005 at 7:00 pm (CST)

WHERE:

Fargo	North Dakota State University E. Morrow Lebedeff, Room 183
Grand Forks	University of North Dakota Gamble Hall, Room 120
Bismarck	Veterans Memorial Public Library 515 North 5th Street, Lower Level

RECEIVED
FEB 10 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

The public will also be able to hear the input session by connecting to the Commission's web site at www.psc.state.nd.us then clicking on the "Broadcast of Public Input Sessions" link. The Commission will receive e-mail questions during the input session at ndpsc@state.nd.us

Mail comments to the Public Service Commission, 600 East Boulevard Avenue, Dept 408, Bismarck ND 58505-0480 Individuals requiring special accommodations contact Illona A Jeffcoat-Sacco (1-701-328-2400 or TTY 1-800-366-6888) *at least one working day prior* to the meeting

RECEIVED
APR - 6 2005
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Affidavit of Publication

Colleen Park, being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:

   PSC, Northern States Informal Hearing, 1 time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of ND

County of Burleigh

Subscribed and sworn to before me this 4 day of April 2005.

Kim Arman

KIM ARMAN
Notary Public
State of North Dakota
My Commission Expires July 14, 2009

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Affidavit of Publication

by North Dakota Advertising Service, Inc

04/06/2005 C Comm Legal PUD (4) Mike ALJ

North Dakota Newspaper Association
1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

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APR - 6 2005
PUBLIC SERVICE COMM
EXECUTIVE SECRE

INVOICE

Order **20331-05033PP0** Invoice # **53016**

April 5, 2005

Attn: ILLONAA. JEFFCOAT-SACCO
PUBLIC SERVICE COMMISSION
600 E. BOULEVARD AVE.
STATE CAPITOL
BISMARCK, ND 58505
Voice 701-328-4076

Advertiser **Public Utilities Division**

P.O # **PU-04-578**

Amount Due **$73.49**

Amount Paid

Please detach and return this portion with your payment

Public Utilities Division Invoice # 20331-05033PP0-53016 PO# PU-04-578

Ad Size	*Rate Type*	*Rate*	*Total*	*Discount*	*(%)*	*Caption*	*Page*	*Run Date*
Fargo, The Forum (Fargo ND)								
52 00	SPR2	0 71	36 92	0 00		Northern States Inform		03/21/05
Grand Forks Herald (Grand Forks ND)								
53 00	SPR2	0 69	36 57	0 00		Northern States Inform		03/17/05

Gross Advertising	73.49	Total Misc	0 00	Amount Paid	0 00
Agency Discount		Tax	0 00	Adjustments	0 00
Other Discount	0.00	Total Billed	73 49	Payment Date	
Service Charge	0 00	Unbilled	0 00	Balance Due	73 49

76 **PU-04-578** Pages 1

Affidavit of Publication

by North Dakota Advertising Service, Inc

04/06/2005 C Comm Legal PUD (4) Mike ALJ

State Of North Dakota
Public Service Commission
March 9, 2005
Notice Of Informal Hearing And Notice Of
Cancellation Of Formal Hearing
Case No: PU-04-578

Fargo 3-21

Grand Forks 3-17

NORTH DAKOTA PUBLIC SERVICE COMMISSION
ADMINISTRATION DIVISION
PERSONAL SERVICE CONTRACT
SFN 53824 (7/2003)

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FEB - 4 2005
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Administrator:	State of North Dakota Public Service Commission	600 E Boulevard Avenue Bismarck, ND 58505-0480 Phone· (701) 328-2400

Date: January 26, 2005

Susan E. Wefald **Commissioner**	**Tony Clark** **President**	**Kevin Cramer** **Commissioner**

Contractor		
Larkin & Associates, PLLC		
Name		
15728 Farmington Rd	Livonia MI 48154	734-522-3420
Address	**City/State/Zip**	**Phone**
Hugh Larkin, Jr		Senior Partner
Typed Name		**Title**
Hugh Larkin Jr		1-28-05
Signature		**Date**

Agreement Information	
PSC Case No	PU-04-578
Contract No	PU-497-05
Start Date	1-28-05
End Date	June 30, 2005
Program Title	NSP Natural Gas Rate Application

Type of Contract:
(X) Cost Reimb
( ) Fixed Price
( ) Unit Price
( ) Other

Budget Information	
Cost Center	7700
Services	$14,000
Optional on-site review	
Expenses	$1,000
Not to exceed	$15,000

Type of Contractor:
( ) Individual
( ) Corporation
(X) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other – Joint Venture

This contract is entered into between the State of North Dakota acting through the Public Service Commission (State) and Larkin & Associates, PLLC (Contractor) This contract consists of this sheet, general provisions and specific provisions

59 PU-04-578 Pages 8
Signed Contract No PU-497-05
by Larkin & Associates
02/04/2005 C Comm Legal PUD (4) Mike ALJ

GENERAL PROVISIONS

CONTRACTUAL FEATURES

LEGAL AUTHORITY

The Contractor assures that it possesses legal authority to participate in this contract

ASSIGNMENT/SUBCONTRACTING

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet without the State's express written consent

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract Any such subcontract must acknowledge the bonding nature of the contract and must incorporate this contract, including any attachments Contractor is solely responsible for the performance of any subcontractor Contractor shall not have the authority to contract for or incur obligations on behalf of the State

TERMINATION

The State, by written notice of default listing causes and reasons, may terminate this contract in whole or in part if (1) the Contractor fails to provide services required by this contract within the time specified or any extension agreed to by the State, or (2) the Contractor fails to perform any of the other conditions or provisions of this contract, or so fails to pursue the work so as to endanger performance of this contract in accordance with its terms The State will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the State

This contract may be terminated in whole or in part without cause by mutual consent of the Contractor and the State The parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated

The State may terminate this contract effective upon delivery of written notice to the Contractor or on any later date stated in the notice in the event (1) funding from federal, state or other sources is not obtained and continued at levels sufficient to allow for purchases of the services or supplies in the indicated quantities or term, (2) federal or state laws or rules are modified or interpreted in a way that the services are no longer allowable or appropriate for purchase under this contract or are no longer eligible for the funding proposed for payments authorized by this contract, or (3) any license, permit or certificate required by law or rule, or by the terms of this contract, is for any reason denied, revoked, suspended or not renewed

Any contract that extends beyond the current biennium may be terminated by the State if sufficient funds are unavailable, if the law regarding the contract is changed, or without cause at any time

The rights and remedies of the State provided in the termination provisions related to defaults by the Contractor are not exclusive and are in addition to any other rights and remedies provided by law or under this contract

FORCE MAJEURE

Contractor will not be held responsible for delay or default caused by fire, riot, acts or God or war if the event is beyond the Contractor's reasonable control and the Contractor gives notice to the State immediately upon occurrence of the event causing the delay or default or which is reasonably expected to cause a delay or default

DISPUTES

The Contractor agrees to attempt to resolve disputes arising from this contract by informal administrative process and negotiations in lieu of litigation Continued

performance by the Contractor during disputes is assured

The State does not agree to any form of binding arbitration, mediation, or other forms of mandatory alternative dispute resolutions The parties have the right to enforce their rights and remedies in judicial proceedings The State does not waive any right to a jury trial

MERGER AND MODIFICATION

This contract constitutes the entire agreement between the parties There are no understandings, agreements, or representations, oral or written, not specified within this contract This contract may not be modified, supplemented or amended, in any manner, except by written agreement signed by both parties

SEVERABILITY

If any term of this contract is declared by a court having jurisdiction to be illegal or unenforceable, the validity of the remaining terms shall not be affected, and if possible, the rights and obligations of the parties are to be construed and enforced as if the contract did not contain that term.

NOTICE

All notices or other communications required under this contract shall be given by registered or certified mail and are complete on the date mailed when addressed to the parties at the following addresses

State

Illona A Jeffcoat-Sacco
Executive Secretary
Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck, ND 58505-0480

Contractor

Hugh Larkin, Jr
Larkin & Associates, PLLC
15728 Farmington Road
Livonia, MI 48154

APPLICABLE LAW AND VENUE

This contract is governed by and construed in accordance with the laws of the State of North Dakota Any action to enforce this contract must be brought in the District Court of Burleigh County, North Dakota

SPOLIATION – NOTICE OF POTENTIAL CLAIMS

Contractor shall promptly notify State of all potential claims that arise or result from this contract Contractor shall also take all reasonable steps to preserve all physical evidence and information that may be relevant to the circumstances surrounding a potential claim, while maintaining public safety, and grants to the State the opportunity to review and inspect the evidence, including the scene of an accident

INDEMNITY

Contractor shall defend, indemnify, and hold harmless the State of North Dakota, its agencies, officers and employees, from any and all claims of any nature including all costs, expenses and attorneys' fees, that may in any manner result from or arise out of this agreement, except for claims resulting from or arising out of the State's sole negligence The legal defense provided by Contractor to the State under this provision must be free of any conflicts of interest, even if retention of separate legal counsel for the State is necessary Contractor also agrees to defend, indemnify, and hold the State harmless for all costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided herein This obligation shall continue after the termination of this agreement

CONFIDENTIALITY

Contractor agrees not to use or disclose any information it receives from the State under this contract that the State has previously identified as confidential or exempt from mandatory public disclosure

except as necessary to carry out the purposes of this contract or as authorized in advance by the State The State agrees not to disclose any information it receives from Contractor that the Contractor has previously identified as confidential and which the State determines in its sole discretion is protected from mandatory public disclosure under a specific exception to the North Dakota open records law, N D C C. ♣44-04-18 The duty of the State and Contractor to maintain confidentiality of information under this section continues beyond the term of this contract, or any extensions or renewals of it

Contractor understands that, except for disclosures prohibited in N D C C Chapter 47-25 1, the State must disclose to the public upon request any records it receives from Contractor Contractor further understands that any records that are obtained or generated by the Contractor under this contract, except for records that are confidential under N D C C Chapter 47-25 1, may, under certain circumstances, be open to the public upon request under North Dakota open records law Contractor agrees to contact the State immediately upon receiving a request for information under the open records law and to comply with the State's instructions on how to respond to the request

INSURANCE

a. Required Coverages.

Contractor shall secure and keep in force during the term of this contract, from an insurance company, government self-insurance pool or government self-retention fund authorized to do business in North Dakota, the following insurance coverages covering the Contractor for any and all claims of any nature which may in any manner arise out of or result from this contract

(1) Commercial general liability, including products or completed operations coverage (if applicable), with minimum liability limits of $250,000 per person and $1,000,000 per occurrence
(2) Professional errors and omissions, including a three year "tail coverage endorsement," with minimum liability limits of $1,000,000 per occurrence and in the aggregate
(3) Automobile liability, with minimum liability limits of $250,000 per person and $1,000,000 per occurrence
(4) Workers compensation coverage meeting all North Dakota statutory requirements The policy shall provide coverage for all states of operation that apply to the performance of this contract
(5) Employer's liability or "stop gap" insurance of not less than $1,000,000 as an endorsement on the workers compensation or commercial general liability insurance if Contractor is domiciled outside the State of North Dakota.

b. General Insurance Requirements.

The insurance coverages listed above must meet the following additional requirements

(1) Any deductible or self insured retention amount or similar obligation under the policies shall be the sole responsibility of the Contractor The amount of any deductible or self-retention is subject to approval by the State
(2) This insurance may be in policy or policies of insurance, primary and excess, including the so-called umbrella or catastrophe form and must be placed with insurers rated "A" or better by A M Best Company, Inc , provided any excess policy follows form for coverage Less than an "A" rating must be approved by the State The policies shall be in form and terms approved by the State
(3) The State will be defended, indemnified, and held harmless to the full extent of any coverage actually secured by the Contractor in excess of the minimum requirements set forth above The duty to indemnify the State under this agreement

shall not be limited by the insurance required in this contract

(4) The State of North Dakota and its agencies, officers, and employees (State) shall be endorsed on the commercial general liability policy, including any excess policies (to the extent applicable), as additional insured The State shall have all the rights and coverages as Contractor under said policies. The additional Insured endorsement for the commercial general liability policy shall be written on a form equivalent to ISO 1985 CG 20 10-form, or such other form as approved by the State, and shall not limit or delete State's coverage in any way based upon State's acts or omissions

(5) The insurance required in this agreement, through a policy or endorsement, shall include
   a a "Waiver of Subrogation" waiving any right to recovery the insurance company may have against the State,
   b a provision that the policy and endorsements may not be canceled of modified without thirty (30) days' prior notice to the undersigned State representative,
   c c a provision that any attorney who represents the State under this policy must first qualify as and be appointed by the North Dakota Attorney General as a Special Assistant Attorney General as required under N D C C § 54-12-08,
   d a provision that Contractor's insurance coverage shall be primary (i e , pay first) as respects any insurance, self-insurance or self-retention maintained by the State, and that any insurance, self-insurance or self-retention maintained by the State shall be in excess of the Contractor's insurance and shall not contribute with it;
   e cross liability/severability of interest for all policies and endorsements

(6) The legal defense provided to the State under the policy and any endorsements must be free of any conflicts of interest, even if retention of separate legal counsel for the State is necessary

(7) The Contractor shall furnish a certificate of insurance and all endorsements to the undersigned State representative prior to commencement of this agreement

(8) Failure to provide insurance as required in this agreement is a material breach of contract entitling the State to terminate this agreement immediately

ATTORNEY FEES

In the event a lawsuit is instituted by the State to obtain performance due of any kind under this contract, and the State is the prevailing party, Contractor shall, except when prohibited by N D C C § 28-26-04, pay the State's reasonable attorney fees and costs in connection with the lawsuit

INDEPENDENT ENTITY

Contractor is an independent entity under this contract and is not a State employee for any purpose, including but not limited to the application of the Social Security Act, the Fair Labor Standards Act, the Federal Insurance Contribution Act, the North Dakota Unemployment Compensation Law and the North Dakota Workers' Compensation Act The Contractor retains

sole and absolute discretion in the manner and means of carrying out the Contractor's activities and responsibilities under this contract, except to the extent specified in the contract

FISCAL RESPONSIBILITIES

RECORDS

All records, regardless of physical form, and the accounting practices and procedures of the Contractor relevant to this contract are subject to examination by the North Dakota State Auditor or the Auditor's designee. The Contractor shall maintain and retain all books, records, and other documents required by the State and to produce program narrative and statistical data at times prescribed by the State relevant to this agreement for four years after final payment Records shall be retained beyond four years if audit findings have not been resolved

NO CLAIM FOR ADDITIONAL WORK

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the State.

TIME KEEPING PROCEDURES

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared

MONITORING, EVALUATION AND AUDIT

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the State, or its designee who shall have full access to and the right to examine all books, records and other relevant documents

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring

PREPAYMENT

The State will not make any advance payments before performance by the Contractor under this contract

TAXPAYER ID

Contractor's North Dakota tax ID number is _____

Contractor's federal employer ID number is 38-2437293

PROGRAM REQUIREMENTS

COMPLIANCE WITH LAWS

Contractor agrees to comply with all applicable laws, rules, regulations and policies, including but not limited to those relating to nondiscrimination, accessibility and civil rights Contractor agrees to timely file all required reports, make required payroll deductions, and timely pay all taxes and premiums owed, including but not limited to sales and use taxes and unemployment compensation and workers' compensation premiums Contractor shall have and keep current at all times during the term of this contract all licenses and permits required by law.

EQUAL OPPORTUNITY

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship

NONDISCRIMINATION

This contract and any subcontract hereunder is subject to the Age

Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990

WORK PRODUCT, EQUIPMENT AND MATERIALS

All work product, equipment or materials created or purchased under this contract belong to the State and must be delivered to the State at the State's request upon termination of this contract Contractor agrees that all materials prepared under this contract are "works for hire" within the meaning of copyright laws of the United States and assigns to State all rights and interests Contractor may have in the materials its prepares under this contract, including any right to derivative use of the material Contractor shall execute all necessary documents to enable State to protect its rights under this section Contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts entered into relating to this project.

EFFECTIVENESS OF CONTRACT

This contract is not effective until fully executed by both parties.

SPECIFIC PROVISIONS

Purpose

Northern States Power Company d/b/a Xcel Energy has filed an application to increase its North Dakota natural gas utility service rates To fully pursue and represent its case, staff requires assistance to analyze MDU's filing and to provide written and oral testimony The work will include sufficient detail as is necessary to successfully testify under cross-examination

All work under this contract must be completed prior to the commission's fiscal year ending June 30, 2005 More importantly, the work needs to be sufficiently complete so that the contractor can provide written testimony by a date to be determined and oral testimony at the technical hearing scheduled to begin April 20, 2005

The specific purpose of this contract is to investigate, analyze and provide testimony on NSP's reasonable costs of capital necessary for the provision of natural gas service in North Dakota

The scope of work includes

1 Professional analysis and review of filing
2 Prepare and conduct discovery
3 Periodic progress reports of discovery, conclusions and recommendations to keep staff updated
4 Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document
5 Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding
6 Testify at the hearing
7 Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings
8 After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision

Compensation

The Contractor will be compensated based on periodic submittal of progress reports Final payment will be made upon satisfactory completion of the described project work, as determined by the commission

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed

No part of this contract may be assigned, sublet or subcontracted, except that the Contractor may subcontract with Aaron Rothschild as described in Contractor's proposal received by the Public Service Commission on December 6, 2004

PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

NEWS RELEASE ****For Immediate Release****
Monday, January 31, 2005 **Phone 701-328-2400**
Commissioners Clark, Cramer, and Wefald

Xcel Gas Rate Public Meetings Scheduled

The North Dakota Public Service Commission (PSC) encourages natural gas customers of Xcel Energy to participate in public meetings on an Xcel proposal to increase natural gas rates. The meeting will be held Monday, February 7 in three different locations in the state via interactive video from 7 00-9:00 p m. (Central Time).

Xcel customers who come to the meeting will have a chance to learn more about the case, and offer comments to the Commission about the proposed increases.

"With the extreme volatility of the commodity price of gas, it is critical that we get all of the input we can on this case," said Commissioner Kevin Cramer. "We want to hear directly from consumers on what impact the increases being proposed by the company will have."

"This is an important case, and I hope that people will come and share their thoughts on the proposed increases. A major issue in this case is that Xcel proposes to allocate most of the $1,280,232 increase to residential customers," stated Commissioner Susan Wefald.

"The meetings are an informal way for consumers to learn more about the new rates Xcel has proposed," said Commissioner Tony Clark. "Consumer input helps us know what questions North Dakotans want answered about this case."

Xcel is proposing an annual net revenue increase of $1,280,232. Xcel proposes to change natural gas rates for residential customers by increasing the Basic Service Charge per month from $5 50 to $8.50 and by decreasing the Distribution Charge per therm from $0.12480 to $0.12388. Xcel proposes to increase natural gas rates to small interruptible customers by increasing the Distribution Charge per therm from $0 07310 to $0.07740. Xcel proposes to increase natural gas rates to large interruptible customers by increasing the Distribution Charge per therm from $0.04390 to $0 04632. Xcel proposes to change natural gas rates to commercial and industrial service customers by changing the Basic Service Charge per month from $14.00 to $20 00 and changing the Distribution Charge per therm from $0.11280 to $0.10120 Residential, commercial, and industrial customers will be able to determine whether their bill will change by reviewing their gas usage throughout the year.

Xcel anticipates that an average residential customer bill will increase by $2-$3 per month. Xcel further proposes for residential customers a rate element that would slightly raise prices in warm months and slightly decrease prices in cold months. This rate element would help to weather-normalize the recovery of distribution costs.

Xcel's proposed rate changes would not affect the cost of purchased gas, which is separately recovered through the Cost of Gas billing provision.

Xcel last sought an increase in natural gas rates in 2000, which was granted in 2001.

The Public Input sessions will be held at the following locations:

North Dakota State University
E. Morrow Lebedeff, Room 183
Fargo ND

University of North Dakota
Gamble Hall, Room 120
Grand Forks ND

Bismarck Veterans Memorial Public Library
515 North 5th Street, Lower Level
Bismarck ND

The public can access the broadcast by visiting the Commission's website, www.psc.state.nd us and clicking on "Media", then "What's New" or "Commission Live." Look for "Public Input Sessions & Broadcast of Public Input Sessions over IVN". For more information call 701-328-2400 or write to 600 E. Boulevard Ave., Dept. 408, Bismarck, ND 58505-0480.

-END-

Daily Newspapers

* Todd McDonald Bureau Chief
1020 S 25th St
Fargo ND 58104

need to mail. mail no e-mail

Phyllis Mensing
Associated Press
PO Box 1018
Bismarck ND 58502-1018

Dale Wetzel
Associated Press
State Capitol Press Room
INSIDE MAIL
Bismarck nd 58505

Capitol Reporter
Bismarck Tribune
State Capitol Press Room
Inside Mail

Gordon Weixel, Editor
Devils Lake Journal
PO Box 1200
Devils Lake ND 58301-1200

Capitol Reporter
Grand Forks Herald
State Capitol Press Room
Bismarck ND 58505

* Mike Jacobs, Editor
Grand Forks Herald
PO Box 6008
Grand Forks ND 58206-6008

✓

Bryan Obenchain, Editor
Minot Daily News
PO Box 1150
Minot ND 58702-1150

Executive Director
North Dakota Republican
PO Box 1917
Bismarck ND 58502-1917

* The Associated Press
101 North Fifth Street
PO Box 3026
Fargo ND 58108-3026
Alan Reed, Managing Edito
The Dickinson Press
PO Box 1367
Dickinson ND 58601-1367

✓

Mitzi Moe
The Daily News
PO Box 760
Wahpeton ND 58074-0760

* Lou Ziegler, Editor
The Fargo Forum
PO Box 2020
Fargo ND 58107-2020

✓

* Janell Cole Capitol Reporter
The Forum
State Capitol Press Room
Bismarck ND 58505

need to fax no e-mail # 95 or 224-0089

Kathy Steiner, Editor
The Jamestown Sun
PO Box 1760
Jamestown ND 58402-1760

Clif Wasfaret
Valley City Times-Record
PO Box 697
Valley City ND 58072-0697

Don Mrachek
Williston Daily Herald
PO Box 1447
Williston ND 58802-1447

Radio/TV

News Director
KACL FM and KLXX AM Radio
PO Box 1377
Bismarck ND 58502-1377

KAOC, KAUJ, KYTZ FM and KXPO AM radio
856 W 12 St
Grafton ND 58237

KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

News Director
KBMY TV
919 South 7th Street
Bismarck ND 58504

KCJB, KRRZ AM and KMXA, KYYZ, KIZZ
PO Box 10
Minot ND 58702-0010

KCSI TV 32
PO Box 608
Jamestown ND 58402-0608

News Director
KDDR AM
412 Main Avenue
Oakes ND 58474

News Director
KDLR AM and KDVL, KQZZ FM Radio
Box 190
Devils Lake ND 58301-0190

News Director
KDSU KCND KPRJ KMPR KPPR KDPR
1814 North 15th Street
Bismarck ND 58501

Program Director
KEYA FM Radio
P O Box 190
Belcourt ND 58316-0190

News Room
KACL, KKCT, KBYZ FM and KLXX AM Radio
PO Box 2156
Bismarck ND 58502-1233

News Director
KBME KDSE KJRE KFME KGFE KSRE KWSE-TV
PO Box 3240
Fargo ND 58108-3240

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

Program Director
KBTO FM Radio
PO Box 28
Bottineau ND 58318-0028

News Director
KCNN AM, and KZLT FM Radio
667 DeMers Avenue, Suite 1003
Grand Forks ND 58201

News Director
KDAK AM
Box 50
Carrington ND 58421-0050

News Director
KDIX AM Radio
119 2nd Ave W
Dickinson ND 58601-5115

News Director
KDSR FM Radio
P O Box 1487
Williston ND 58802-1487

Rich Mattern
KDSU-FM Radio
PO Box 5347
Fargo ND 58105-5347

News Director
KEYZ AM, KHTC FM and KYYZ FM Radio
PO Box 2048
Williston ND 58802-2048

KFME TV
207 North Fifth Street
Fargo ND 58108

News Director
KFYR AM and KYYY FM Radio
PO Box 1658
Bismarck ND 58502-1658

News Director
KHOL AM Radio
P O Box 819
Beulah ND 58523-0819

News Director
KLTC AM, KCAD FM Radio, and KZRX
11291 39th St SW
Dickinson ND 58601-9206

KMOT TV
Box 1120
Minot ND 58702-1120

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

News Director
KOVC AM and KQDJ FM Radio
136 North Central Avenue
P O Box 994
Valley City ND 58072-0994

KQCD TV
PO Box 1577
Dickinson ND 58602-1577

KQWB, KPFX, KVOX, KLTA FM, KQWB AM Ra
PO Box 9919
Fargo ND 58106-9919

KTGO-AM
Box 457
Tioga ND 58852-0457

News Director
KFNW AM/FM Radio
5702 52nd Ave S
Fargo ND 58104

News Director
KFYR TV
P O Box 1738
Bismarck ND 58502-1738

KKXL AM and KKXL, KQHT, KJKJ, KSNR
PO Box 13598
Grand Forks ND 58208-3598

KMAV AM/FM RADIO
PO Box 216
Mayville ND 58257-0216

News Director
KNDC AM Radio
P O Box 151
Hettinger ND 58639-0151

News Director
KNOX FM Radio
P O Box 13638
Grand Forks ND 58208-3638

News Director
KPOK AM Radio
P O Box 829
Bowman ND 58623-0829

News Director
KQLX AM/FM Radio
P O Box 1008
Lisbon ND 58054-1008

News Director
KSJB AM and KSJZ FM Radio
PO Box 5180
Jamestown ND 58402-5180

KUMV-TV
PO Box 1287
Williston ND 58802-1287

News Director
KUND AM Radio
314 Cambridge
Grand Forks ND 58203

News Director
KVLY TV
P O Box 1878
Fargo ND 58107-1878

News Director
KVOX, KFGO AM and KFGO, WDAY, KRVI,
B-93
1020 S 25th Street
Fargo ND 58108

News Director
KVRR-Fox, KBRR, KNRR, KJRR TV
PO Box 9115
Fargo ND 58106-9115

KXGT and KYNU FM, KQDJ AM Radio
203 1st Ave S
PO Box 1170
Jamestown ND 58402-1170

KXJB-TV 4
4302 13th Ave S
Fargo ND 58103-3313

News Director
KXMA-TV
Drawer B
Dickinson ND 58601

KXMB TV
Box 1617
Bismarck ND 58502-1617

KXMC TV
Box 1686
Minot ND 58701-1686

KXMD-TV
PO Box 790
Williston ND 58802-0790

KXMR, KFYR AM and KYYY FM Radio
PO Box 1658
Bismarck ND 58502-1658

News Director
KXND, KMCY TV
900 N Broadway
PO Box 2276
Minot ND 58702-2276

News Director
KYCK FM and KNOX AM Radio
PO Box 13638
Grand Forks ND 58208-3638

KZZJ-AM
230 Highway 2 SE
Rugby ND 58368-2446

News Director
KZZY FM Radio
P O Box 882
Devils Lake ND 58301-0882

WDAY AM-FM & TV
P O Box 2466
Fargo ND 58108-2466

WDAY AM-FM & TV
PO Box 2466
Fargo ND 58108-2466

WDAZ-TV
PO Box 12639
Grand Forks ND 58208-2639

Weekly Newspapers

News Desk
Adams County Record
PO Box 749
Hettinger ND 58639-0749

News Desk
Benson County Farmers Press
PO Box 98
Minnewaukan ND 58351-0098

Billings County Pioneer
PO Box 406
Medora ND 58645-0406

News Desk
Bowman County Pioneer
PO Box F
Bowman ND 58623-0120

News Desk
Carson Press
PO Box 100
Elgin ND 58533-0100

News Desk
Cavalier County Republican
710 Third Street
Langdon ND 58249

News Desk
Dunn County Herald
PO Box 609
Killdeer ND 58640-0609

News Desk
Emmons County Record
PO Box 38
Linton ND 58552-0038

News Desk
Farm & Ranch Guide
PO Box 1977
Bismarck ND 58502-1977

News Desk
Glen Ullin Times
PO Box 668
Glen Ullin ND 58631-0668

News Desk
Agweek Magazine
PO Box 6008
Grand Forks ND 58206-6008

News Desk
Beulah Beacon
324 2nd Ave. NE
Beulah ND 58523

News Desk
Bottineau Courant
PO Box 29
Bottineau ND 58318-0029

News Desk
Burke County Tribune
PO Box 40
Bowbells ND 58721-0040

News Desk
Cass County Reporter
PO Box 190
Casselton ND 58012-0190

News Desk
Dickey County Leader
PO Box 9
Ellendale ND 58436-0009

News Desk
Edgeley Mail
PO Box 278
Edgeley ND 58433-0278

News Desk
Enderlin Independent
209 4th Avenue
Enderlin ND 58027

News Desk
Foster County Independent
PO Box 138
Carrington ND 58421-0138

News Desk
Golden Valley News
PO Box 156
Beach ND 58621-0156

News Desk
Grant County News
PO Box 100
Elgin ND 58533-0100

News Desk
Griggs County Sentinel-Courier
PO Box 525
Cooperstown ND 58425-0525

News Desk
Hazen Star
PO Box 508
Hazen ND 58545-0508

News Desk
Hebron Herald
PO Box 9
Hebron ND 58638-0009

News Desk
High Plains Reader
118 Broadway
Fargo ND 58102

News Desk
Hillsboro Banner
PO Box 39
Hillsboro ND 58045-0039

News Desk
Kenmare News
PO Box 896
Kenmare ND 58746-0896

News Desk
Kulm Messenger
PO Box J
Kulm ND 58456

News Desk
Lakota American
PO Box 507
Lakota ND 58344-0507

News Desk
LaMoure Chronicle
PO Box 196
LaMoure ND 58458-0196

News Desk
Leader
227 Steen Blvd.
Grand Forks AFB ND 58205

News Desk
Leader-News
PO Box 340
Washburn ND 58577-0340

News Desk
Mandan News
PO Box 908
Mandan ND 58554-0908

News Desk
McClusky Gazette
PO Box 457
McClusky ND 58463-0457

News Desk
McKenzie County Farmer
PO Box 587
Watford City ND 58854-0587

News Desk
McLean County Independent
PO Box 309
Garrison ND 58540-0309

News Desk
McLean County Journal
PO Box 220
Turtle Lake ND 58575-0220

News Desk
Mountrail County Promoter
PO Box 99
Stanley ND 58784-0099

News Desk
Mountrail County Record
PO Box 8
Parshall ND 58770-0008

News Desk
Mouse River Journal
PO Box 268
Towner ND 58788-0268

News Desk
Napoleon Homestead
PO Box 29
Napoleon ND 58561-0029

News Desk
Ness Publications
PO Box 157
Fordville ND 58231-0157

Leader-Tribune
Ness Publications
PO Box 157
Fordville ND 58231-0157

Nelson County Arena
Ness Publications
PO Box 157
Fordville ND 58231-0157

The Express
Ness Publications
PO Box 157
Fordville ND 58231-0157

News Desk
New Rockford Transcript
PO Box 752
New Rockford ND 58356-0752

News Desk
New Town News
PO Box 730
New Town ND 58763-0730

News Desk
Oakes Times
PO Box 651
Oakes ND 58474-0651

News Desk
Ransom County Gazette
PO Box 473
Lisbon ND 58054-0473

News Desk
Richland County News-Monitor
PO Box 190
Hankinson ND 58041-0190

Adams Standard
Ness Publications
PO Box 157
Fordville ND 58231-0157

Hatton Free Press
Ness Publications
PO Box 157
Fordville ND 58231-0157

McVille Messenger
Ness Publications
PO Box 157
Fordville ND 58231-0157

Pembina New Era
Ness Publications
PO Box 157
Fordville ND 58231-0157

Tri-County Sun
Ness Publications
PO Box 157
Fordville ND 58231-0157

News Desk
New Salem Journal
PO Box 416
New Salem ND 58563-0416

News Desk
Northern Star
PO Box 2183
Minot ND 58702-2183

News Desk
Pierce County Tribune
PO Box 385
Rugby ND 58368-0385

News Desk
Renville County Farmer
PO Box 98
Mohall ND 58761-0098

News Desk
Steele County Press
PO Box 475
Finley ND 58230-0475

News Desk
Steele Ozone-Press
PO Box 350
Steele ND 58482-0350

News Desk
The Ashley Tribune
PO Box 178
Ashley ND 58413-0178

News Desk
The Cavalier Chronicle
PO Box 520
Cavalier ND 58220-0520

News Desk
The Herald
PO Box 517
New England ND 58647-0517

News Desk
The Herald-Press
1015 Lincoln Avenue
Harvey ND 58341

News Desk
The Journal
PO Box E
Crosby ND 58730

News Desk
The Litchville Bulletin
PO Box 46
Litchville ND 58461-0046

The Shopper
PO Box 2324
Williston ND 58852-2324

News Desk
The Teller
PO Box 247
Milnor ND 58060-0247

News Desk
The Walsh County Record
PO Box 471
Grafton ND 58237-0471

News Desk
Tioga Tribune
PO Box 700
Tioga ND 58852-0700

News Desk
Towner County Record-Herald
PO Box 519
Cando ND 58324-0519

News Desk
Traill County Tribune
PO Box 567
Mayville ND 58257-0567

News Desk
Tri-County News
PO Box 314
Gackle ND 58442-0314

News Desk
Turtle Mountain Star
PO Box 849
Rolla ND 58367-0849

News Desk
Turtle Mountain Times
PO Box 1270
Belcourt ND 58316-1270

News Desk
Underwood News
PO Box 179
Underwood ND 58576-0179

News Desk
Valley News & Views
PO Box 309
Drayton ND 58225-0309

News Desk
Velva Voice
PO Box 630
Velva ND 58790-0630

News Desk
Walhalla Mountaineer
PO Box 497
Walhalla ND 58282-0497

News Desk
Walsh County Press
PO Box 49
Park River ND 58270-0049

News Desk
Westhope Standard
PO Box 267
Westhope ND 58793-0267

News Desk
West Fargo Pioneer
PO Box 457
West Fargo ND 58078-0457

News Desk
Wishek Star
PO Box 275
Wishek ND 58495-0275

Kevin —
Any other
than those
we discussed
for the NSP
case?

INDEX OF COMPANY'S SERVICE AREA

Section No 3
Original Sheet No 1
Relocated from NDPSC No 1 Sheet No G 2

Northern States Power Company supplies gas service at retail in the State of North Dakota in the communities and counties shown below.

COMMUNITIES	AREA OFFICE
Buffalo	Fargo
Casselton*	Fargo
Emerado	Grand Forks
Fargo*	Fargo
Grand Forks*	Grand Forks
Mapleton	Fargo
Oriska	Fargo
Riverside	Fargo
Tower City	Fargo
West Fargo	Fargo
Unincorporated Areas in Cass County	Fargo
Unincorporated Areas in Grand Forks County	Grand Forks

* Surcharge applicable - See Surcharge Rider

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E. Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

John Thornton
Thornton Financial Consulting
7929 E Joshua Tree Ln
Scottsdale AZ 85250-7967

RE: NSP Consulting Proposal, Case No PU-04-578

Dear Mr. Thornton:

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application. After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC.

We will keep your company on our mailing list so you will receive future opportunities to bid.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

57 **PU-04-578** Pages 1

Thank you letter to John Thornton

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

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TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

James Proctor President
Free State Synergies
4803 Hallbrook Dr
Lawrence KS 66047

RE: NSP Consulting Proposal, Case No PU-04-578

Dear Mr. Proctor.

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application. After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC.

We will keep your company on our mailing list so you will receive future opportunities to bid

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

56 PU-04-578 Pages 1

Thank you letter to James Proctor

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

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TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

Frank Radigan
Hudson River Energy Group
120 Washington Ave
Albany NY 12210

RE: NSP Consulting Proposal, Case No. PU-04-578

Dear Mr. Radigan

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC.

We will keep your company on our mailing list so you will receive future opportunities to bid

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

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Thank you letter to Frank Radigan

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
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Kevin Cramer

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e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

Gregory Loyd Mann
Gorham Gold Greenwich & Associates
P O Box 23626
Overland Park KS 66283-0626

RE: NSP Consulting Proposal, Case No. PU-04-578

Dear Mr. Mann·

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application. After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC

We will keep your company on our mailing list so you will receive future opportunities to bid

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

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Thank you letter to Gregory Loyd Mann

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
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TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

Charles W King President
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Ste 410
Washington D C 20005

RE: NSP Consulting Proposal, Case No. PU-04-578

Dear Mr King.

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application. After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC.

We will keep your company on our mailing list so you will receive future opportunities to bid

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

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Thank you letter to Charled W King

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

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Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 27, 2005

Wade Druin
School of Business
University of South Dakota
414 E Clark St
Vermillion SD 57069-2390

RE: NSP Consulting Proposal, Case No PU-04-578

Dear Mr. Druin:

Thank you for submitting a proposal for consulting work in NSP's recent gas rate increase application. After reviewing the bid proposals, the Commission decided to hire Larkin & Associates, PLLC.

We will keep your company on our mailing list so you will receive future opportunities to bid.

Sincerely,

Sharon Helbling
Public Utilities Division

Sdh

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Thank you letter to Wade Druin

by Public Service Commission

01/27/2005 C Comm Legal PUD (4) Mike ALJ

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

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Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

January 26, 2005

Hugh Larkin Jr
Larkin & Associates PLLC
15728 Farmington Rd
Livonia MI 48154

Dear Mr Larkin:

Enclosed is Contract No. PU-497-05 for consulting services in Case No. PU-04-578 Please sign both copies of the contract, keep one copy for your files and return one copy to me When you sign the contract, please write in the "start date" of the contract as of the date you sign it.

When submitting invoices for payment, **please send them directly to Mike Diller** and identify the case number for each invoiced amount.

If you have any questions, please call me at 701-328-4076.

Sincerely,

Sharon Helbling
Public Utilities Division

Enclosures

51 **PU-04-578** Pages 1

Cover letter to Larkin & Associates re Contract No PU-497-05 by Public Service Commission

01/26/2005 C Comm Legal PUD (4) Mike ALJ

APPROVED
DATE 1-26-05
KMF

MOTION

January 26, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission execute a contract with Larkin & Associates, PLLC for consulting services in Northern States Power Company's Natural Gas Rate Increase Application, Case No. PU-04-578

JRL/sdh

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Motion approved to execute a contract
w/Larkin & Assoc
by Public Service Commission

01/26/2005 C Comm Legal PUD (4) Mike ALJ

NORTH DAKOTA PUBLIC SERVICE COMMISSION
ADMINISTRATION DIVISION
PERSONAL SERVICE CONTRACT
SFN 53824 (7/2003)

Administrator:	State of North Dakota Public Service Commission	600 E Boulevard Avenue Bismarck, ND 58505-0480 Phone (701) 328-2400

Date: January 26, 2005

Susan E. Wefald **Commissioner**	**Tony Clark** **President**	**Kevin Cramer** **Commissioner**

Contractor		
Larkin & Associates, PLLC		
Name		
15728 Farmington Rd	Livonia MI 48154	734-522-3420
Address	**City/State/Zip**	**Phone**
Hugh Larkin, Jr		Senior Partner
Typed Name		**Title**
Signature		**Date**

Agreement Information

PSC Case No .	PU-04-578
Contract No ·	PU-497-05
Start Date	
End Date:	June 30, 2005
Program Title	NSP Natural Gas Rate Application

Type of Contract: ( ) Fixed Price
(X) Cost Reimb ( ) Unit Price
( ) Other

Budget Information

Cost Center:	7700
Services·	$14,000
Optional on-site review	
Expenses	$1,000
Not to exceed·	$15,000

Type of Contractor: ( ) Individual
( ) Corporation (X) Partnership
( ) Public Agency
( ) Nonprofit Organization
( ) Other – Joint Venture

This contract is entered into between the State of North Dakota acting through the Public Service Commission (State) and Larkin & Associates, PLLC (Contractor) This contract consis of this sheet, general provisions and specific provisions

Pages 8
PU-04-578
49
Contract No PU-497-05 issued to Larkin & Associates PLLC by Public Service Commission
01/26/2005 C Comm Legal PUD (4) Mike ALJ

GENERAL PROVISIONS

CONTRACTUAL FEATURES

LEGAL AUTHORITY

The Contractor assures that it possesses legal authority to participate in this contract

ASSIGNMENT/SUBCONTRACTING

The Contractor may not assign this contract or any part thereof, or assign any of the monies to be paid hereunder, nor shall any part of the work done or material furnished under this contract be sublet without the State's express written consent

The Contractor may not enter into subcontracts for any of the work contemplated under this contract unless included in the specific provisions of this contract. Any such subcontract must acknowledge the bonding nature of the contract and must incorporate this contract, including any attachments. Contractor is solely responsible for the performance of any subcontractor Contractor shall not have the authority to contract for or incur obligations on behalf of the State.

TERMINATION

The State, by written notice of default listing causes and reasons, may terminate this contract in whole or in part if (1) the Contractor fails to provide services required by this contract within the time specified or any extension agreed to by the State; or (2) the Contractor fails to perform any of the other conditions or provisions of this contract, or so fails to pursue the work so as to endanger performance of this contract in accordance with its terms The State will be liable only for payment provisions of this contract for services satisfactorily rendered prior to the effective date of termination

Significant deviation from performance standards in this contract may result in reduced or terminated financial participation of the Contractor, subsequent to negotiations with the State

This contract may be terminated in whole or in part without cause by mutual consent of the Contractor and the State The parties shall agree upon the termination conditions including effective date and in the case of partial terminations, that portion to be terminated.

The State may terminate this contract effective upon delivery of written notice to the Contractor or on any later date stated in the notice in the event (1) funding from federal, state or other sources is not obtained and continued at levels sufficient to allow for purchases of the services or supplies in the indicated quantities or term; (2) federal or state laws or rules are modified or interpreted in a way that the services are no longer allowable or appropriate for purchase under this contract or are no longer eligible for the funding proposed for payments authorized by this contract, or (3) any license, permit or certificate required by law or rule, or by the terms of this contract, is for any reason denied, revoked, suspended or not renewed.

Any contract that extends beyond the current biennium may be terminated by the State if sufficient funds are unavailable, if the law regarding the contract is changed, or without cause at any time

The rights and remedies of the State provided in the termination provisions related to defaults by the Contractor are not exclusive and are in addition to any other rights and remedies provided by law or under this contract

FORCE MAJEURE

Contractor will not be held responsible for delay or default caused by fire, riot, acts or God or war if the event is beyond the Contractor's reasonable control and the Contractor gives notice to the State immediately upon occurrence of the event causing the delay or default or which is reasonably expected to cause a delay or default

DISPUTES

The Contractor agrees to attempt to resolve disputes arising from this contract by informal administrative process and negotiations in lieu of litigation Continued

performance by the Contractor during disputes is assured

The State does not agree to any form of binding arbitration, mediation, or other forms of mandatory alternative dispute resolutions. The parties have the right to enforce their rights and remedies in judicial proceedings The State does not waive any right to a jury trial

MERGER AND MODIFICATION

This contract constitutes the entire agreement between the parties There are no understandings, agreements, or representations, oral or written, not specified within this contract. This contract may not be modified, supplemented or amended, in any manner, except by written agreement signed by both parties.

SEVERABILITY

If any term of this contract is declared by a court having jurisdiction to be illegal or unenforceable, the validity of the remaining terms shall not be affected, and if possible, the rights and obligations of the parties are to be construed and enforced as if the contract did not contain that term.

NOTICE

All notices or other communications required under this contract shall be given by registered or certified mail and are complete on the date mailed when addressed to the parties at the following addresses

State

Illona A. Jeffcoat-Sacco
Executive Secretary
Public Service Commission
600 E Boulevard Ave Dept 408
Bismarck, ND 58505-0480

Contractor

Hugh Larkin, Jr
Larkin & Associates, PLLC
15728 Farmington Road
Livonia, MI 48154

APPLICABLE LAW AND VENUE

This contract is governed by and construed in accordance with the laws of the State of North Dakota Any action to enforce this contract must be brought in the District Court of Burleigh County, North Dakota.

SPOLIATION – NOTICE OF POTENTIAL CLAIMS

Contractor shall promptly notify State of all potential claims that arise or result from this contract Contractor shall also take all reasonable steps to preserve all physical evidence and information that may be relevant to the circumstances surrounding a potential claim, while maintaining public safety, and grants to the State the opportunity to review and inspect the evidence, including the scene of an accident.

INDEMNITY

Contractor shall defend, indemnify, and hold harmless the State of North Dakota, its agencies, officers and employees, from any and all claims of any nature including all costs, expenses and attorneys' fees, that may in any manner result from or arise out of this agreement, except for claims resulting from or arising out of the State's sole negligence. The legal defense provided by Contractor to the State under this provision must be free of any conflicts of interest, even if retention of separate legal counsel for the State is necessary. Contractor also agrees to defend, indemnify, and hold the State harmless for all costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided herein. This obligation shall continue after the termination of this agreement.

CONFIDENTIALITY

Contractor agrees not to use or disclose any information it receives from the State under this contract that the State has previously identified as confidential or exempt from mandatory public disclosure

except as necessary to carry out the purposes of this contract or as authorized in advance by the State The State agrees not to disclose any information it receives from Contractor that the Contractor has previously identified as confidential and which the State determines in its sole discretion is protected from mandatory public disclosure under a specific exception to the North Dakota open records law, N.D.C.C. ♣44-04-18 The duty of the State and Contractor to maintain confidentiality of information under this section continues beyond the term of this contract, or any extensions or renewals of it

Contractor understands that, except for disclosures prohibited in N.D C C. Chapter 47-25.1, the State must disclose to the public upon request any records it receives from Contractor Contractor further understands that any records that are obtained or generated by the Contractor under this contract, except for records that are confidential under N D.C.C Chapter 47-25 1, may, under certain circumstances, be open to the public upon request under North Dakota open records law. Contractor agrees to contact the State immediately upon receiving a request for information under the open records law and to comply with the State's instructions on how to respond to the request.

INSURANCE

a. Required Coverages.

Contractor shall secure and keep in force during the term of this contract, from an insurance company, government self-insurance pool or government self-retention fund authorized to do business in North Dakota, the following insurance coverages covering the Contractor for any and all claims of any nature which may in any manner arise out of or result from this contract·

(1) Commercial general liability, including products or completed operations coverage (if applicable), with minimum liability limits of $250,000 per person and $1,000,000 per occurrence
(2) Professional errors and omissions, including a three year "tail coverage endorsement," with minimum liability limits of $1,000,000 per occurrence and in the aggregate
(3) Automobile liability, with minimum liability limits of $250,000 per person and $1,000,000 per occurrence
(4) Workers compensation coverage meeting all North Dakota statutory requirements The policy shall provide coverage for all states of operation that apply to the performance of this contract.
(5) Employer's liability or "stop gap" insurance of not less than $1,000,000 as an endorsement on the workers compensation or commercial general liability insurance if Contractor is domiciled outside the State of North Dakota.

b. General Insurance Requirements.

The insurance coverages listed above must meet the following additional requirements:

(1) Any deductible or self insured retention amount or similar obligation under the policies shall be the sole responsibility of the Contractor. The amount of any deductible or self-retention is subject to approval by the State
(2) This insurance may be in policy or policies of insurance, primary and excess, including the so-called umbrella or catastrophe form and must be placed with insurers rated "A" or better by A.M. Best Company, Inc , provided any excess policy follows form for coverage. Less than an "A" rating must be approved by the State The policies shall be in form and terms approved by the State
(3) The State will be defended, indemnified, and held harmless to the full extent of any coverage actually secured by the Contractor in excess of the minimum requirements set forth above The duty to indemnify the State under this agreement

shall not be limited by the insurance required in this contract

(4) The State of North Dakota and its agencies, officers, and employees (State) shall be endorsed on the commercial general liability policy, including any excess policies (to the extent applicable), as additional insured. The State shall have all the rights and coverages as Contractor under said policies The additional Insured endorsement for the commercial general liability policy shall be written on a form equivalent to ISO 1985 CG 20 10-form, or such other form as approved by the State, and shall not limit or delete State's coverage in any way based upon State's acts or omissions

(5) The insurance required in this agreement, through a policy or endorsement, shall include:
   a. a "Waiver of Subrogation" waiving any right to recovery the insurance company may have against the State;
   b. a provision that the policy and endorsements may not be canceled of modified without thirty (30) days' prior notice to the undersigned State representative;
   c. c. a provision that any attorney who represents the State under this policy must first qualify as and be appointed by the North Dakota Attorney General as a Special Assistant Attorney General as required under N D.C C § 54-12-08;
   d a provision that Contractor's insurance coverage shall be primary (i e., pay first) as respects any insurance, self-insurance or self-retention maintained by the State, and that any insurance, self-insurance or self-retention maintained by the State shall be in excess of the Contractor's insurance and shall not contribute with it,
   e. cross liability/severability of interest for all policies and endorsements.

(6) The legal defense provided to the State under the policy and any endorsements must be free of any conflicts of interest, even if retention of separate legal counsel for the State is necessary.

(7) The Contractor shall furnish a certificate of insurance and all endorsements to the undersigned State representative prior to commencement of this agreement

(8) Failure to provide insurance as required in this agreement is a material breach of contract entitling the State to terminate this agreement immediately.

ATTORNEY FEES

In the event a lawsuit is instituted by the State to obtain performance due of any kind under this contract, and the State is the prevailing party, Contractor shall, except when prohibited by N D C.C. § 28-26-04, pay the State's reasonable attorney fees and costs in connection with the lawsuit

INDEPENDENT ENTITY

Contractor is an independent entity under this contract and is not a State employee for any purpose, including but not limited to the application of the Social Security Act, the Fair Labor Standards Act, the Federal Insurance Contribution Act, the North Dakota Unemployment Compensation Law and the North Dakota Workers' Compensation Act The Contractor retains

sole and absolute discretion in the manner and means of carrying out the Contractor's activities and responsibilities under this contract, except to the extent specified in the contract.

FISCAL RESPONSIBILITIES

RECORDS

All records, regardless of physical form, and the accounting practices and procedures of the Contractor relevant to this contract are subject to examination by the North Dakota State Auditor or the Auditor's designee. The Contractor shall maintain and retain all books, records, and other documents required by the State and to produce program narrative and statistical data at times prescribed by the State relevant to this agreement for four years after final payment Records shall be retained beyond four years if audit findings have not been resolved.

NO CLAIM FOR ADDITIONAL WORK

No claim for additional services not specifically herein provided, done, or furnished by the Contractor will be allowed, nor shall the Contractor do any work or furnish any material not covered by the contract, unless such work is ordered in writing by the State.

TIME KEEPING PROCEDURES

The Contractor shall require employees and subcontractors, if applicable, whose positions are funded under this contract or included as match, to maintain adequate documentation for services provided. For positions that are funded from more than one source, an analysis of duties performed by program shall also be prepared.

MONITORING, EVALUATION AND AUDIT

The Contractor agrees to cooperate with any monitoring, evaluating and/or audit conducted by the State, or its designee who shall have full access to and the right to examine all books, records and other relevant documents

The Contractor agrees to take immediate corrective action on deficiencies disclosed through program monitoring of costs disallowed in the course of an audit, review, or monitoring.

PREPAYMENT

The State will not make any advance payments before performance by the Contractor under this contract.

TAXPAYER ID

Contractor's North Dakota tax ID number is: _____

Contractor's federal employer ID number is: 38-2437293

PROGRAM REQUIREMENTS

COMPLIANCE WITH LAWS

Contractor agrees to comply with all applicable laws, rules, regulations and policies, including but not limited to those relating to nondiscrimination, accessibility and civil rights. Contractor agrees to timely file all required reports, make required payroll deductions, and timely pay all taxes and premiums owed, including but not limited to sales and use taxes and unemployment compensation and workers' compensation premiums Contractor shall have and keep current at all times during the term of this contract all licenses and permits required by law

EQUAL OPPORTUNITY

No individual shall be excluded from participation in, denied the benefits of, subjected to discrimination under, or denied employment in the administration of or in connection with this contract because of race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship

The Contractor will take affirmative action to ensure that applicants are employed and that employees are treated during employment without regard to their race, color, religion, national origin, disability, age, sex, political affiliation or belief or citizenship

NONDISCRIMINATION

This contract and any subcontract hereunder is subject to the Age

Discrimination Act of 1975, Section 504 of the Rehabilitation Act, Title VI of the Civil Rights of 1964 and the Americans with Disabilities Act of 1990

WORK PRODUCT, EQUIPMENT AND MATERIALS

All work product, equipment or materials created or purchased under this contract belong to the State and must be delivered to the State at the State's request upon termination of this contract. Contractor agrees that all materials prepared under this contract are "works for hire" within the meaning of copyright laws of the United States and assigns to State all rights and interests Contractor may have in the materials its prepares under this contract, including any right to derivative use of the material. Contractor shall execute all necessary documents to enable State to protect its rights under this section. Contractor shall include provisions appropriate to effectuate the purposes of this condition in all subcontracts entered into relating to this project

EFFECTIVENESS OF CONTRACT

This contract is not effective until fully executed by both parties

SPECIFIC PROVISIONS

Purpose

Northern States Power Company d/b/a Xcel Energy has filed an application to increase its North Dakota natural gas utility service rates. To fully pursue and represent its case, staff requires assistance to analyze MDU's filing and to provide written and oral testimony The work will include sufficient detail as is necessary to successfully testify under cross-examination.

All work under this contract must be completed prior to the commission's fiscal year ending June 30, 2005. More importantly, the work needs to be sufficiently complete so that the contractor can provide written testimony by a date to be determined and oral testimony at the technical hearing scheduled to begin April 20, 2005

The specific purpose of this contract is to investigate, analyze and provide testimony on NSP's reasonable costs of capital necessary for the provision of natural gas service in North Dakota.

The scope of work includes:

1. Professional analysis and review of filing
2. Prepare and conduct discovery.
3. Periodic progress reports of discovery, conclusions and recommendations to keep staff updated
4. Prepare written testimony and provide an advanced copy to staff for review prior to submitting as a formal document.
5. Prepare written and oral testimony in rebuttal to testimony of other parties in the proceeding.
6. Testify at the hearing.
7. Assist staff legal counsel in preparation of cross-examination of the witnesses of other parties to the proceedings.
8. After the hearing, assist staff legal counsel in preparation of findings of fact for a proposed commission decision.

Compensation

The Contractor will be compensated based on periodic submittal of progress reports Final payment will be made upon satisfactory completion of the described project work, as determined by the commission.

In the event the case is settled or this agreement is otherwise terminated prior to completion of project work, then compensation will be awarded for work satisfactorily completed.

No part of this contract may be assigned, sublet or subcontracted, except that the Contractor may subcontract with Aaron Rothschild as described in Contractor's proposal received by the Public Service Commission on December 6, 2004.

Scott, Sandi L.
From: Fahn, Patrick J
Sent: Friday, January 21, 2005 4 06 PM
To: 'athorp@forumcomm com', 'cholland@gfherald com
Cc: Anderson, Lori D.
Subject: Newspaper display ad

Attachments: Newspaper Ad for NSP Nat Gas Rate Case Public Info 2-05 pdf

The Public Service Commission requests that the attached display ad be published once on Sunday, February 6, 2005 in each of the following papers

Fargo Forum
Grand Forks Herald

I would appreciate your response to this e-mail confirming that the ad will be published or letting me know if something further is needed.

Newspaper Ad
- NSP Nat Gas R

Please send the bill to:
North Dakota Public Service Commission
600 E Boulevard Avenue
Bismarck, ND 58505-0408

Thank you

Patrick J Fahn
Chief Engineer, Public Utilities Division
600 East Boulevard
Bismarck ND 58505-0480
701-328-4077
701-328-2410 (fax)

pfahn@state nd us

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Newspaper display ad sent to Forum and Hearld requesting publication by Public Service Commission

01/21/2005 C Comm Legal PUD (4) Mike ALJ

Lein, Jerry R.

From: Donna Mullinax [donna@blueridgecs com]
Sent: Wednesday, January 19, 2005 10 51 AM
To: Jerry R Lein
Cc: 'Michael J McGarry', 'DebRollins
Subject: FW. [SPAM] FW Notice of Intent to Award consulting services contract

Jerry,
I appreciate you and Bill taking the time to call me to discuss my email on the Notice of Award for Case No PU-04-578 As I told you, the email was not a formal protest I sent the email in the hopes that we could reach a better understanding of your RFP process to improve our future bidding for projects in North Dakota. We have some very talented people working with us and I wanted to make sure that our next proposal is structured in such a way that we are given due consideration Your planned restructuring of your procurement process should help We look forward to having an opportunity to bid on future work with you

Also, thank you for agreeing to send us a copy of Larkin's winning proposal

With kind regards,

Donna Mullinax, CPA
Vice President/CFO
Blue Ridge Consulting Services, Inc
2131 Woodruff Rd, Suite 2100 PMB 309
Greenville, SC 29607

From: Donna Mullinax [mailto:donna@blueridgecs.com]
Sent: Monday, January 10, 2005 6:17 PM
To: 'Lein, Jerry R.'; 'jeffcoatsacco@state.nd.us'
Cc: 'Michael J. McGarry'; 'DebRollins'
Subject: RE: [SPAM] FW: Notice of Intent to Award consulting services contract

Mr. Lein and Ms. Jeffcoat-Sacco,

We received your notification on the award of Case No. PU-04-578 to Larkin & Associates for $15,000. We are concerned that the basic scope of work was changed and we were not allowed to bid on the altered scope.

The RFP we received specifically asked for a proposal "to investigate, analyze, and provide testimony regarding the fairness and reasonableness of NSP's proposed rate base, cost of capital, regulated net income and rate design" (basically a full rate case analysis). Cost of capital was listed as only one area of interest. Blue Ridge's proposal was developed based on the RFP request and included all areas of interest.

If the RFP had requested a break out of our proposed cost by area of interest, we would have been more than glad to do so. We would have been very competitive if we had been requested to submit a single issue proposal instead of a full rate case analysis.

To help us improve our future bidding, could you please provide us with a copy of the Larkin's proposal so that we can understand how Larkin responded to a full rate case analysis RFP and were awarded a single issue project. We would also greatly appreciate any information on how our proposal compared to the others submitted.

With kind regards,

Donna Mullinax, CPA
Vice President/CFO
Blue Ridge Consulting Services, Inc.

From: Lein, Jerry R. [mailto:jlein@state.nd.us]
Sent: Wednesday, January 05, 2005 2:12 PM
To: 'DMullinax@blueridgecs.com'
Subject: [SPAM] FW: Notice of Intent to Award consulting services contract

-->

From: Lein, Jerry R.
Sent: Wednesday, January 05, 2005 12:55 PM
To: 'charlieking@snavely-king.com'; 'hlarkinjr@aol.com'; 'wdruin@usd.edu'; 'ajg@londoneconomics.com'; 'gregm@ggga.net'; 'ddittemore@cox.net'; 'fradigam@aol.com'; 'john@thorntonfinancial.org'; 'DMullinax@blueridgeecs.com'
Cc: Bendish, Annette M.; Helbling, Sharon D.; Jeffcoat-Sacco, Illona
Subject: Notice of Intent to Award consulting services contract

Thank you for responding to the Commission's recent RFP for consulting services. A hardcopy is being mailed today of the attached Notice of Intent to Award a contract to Larkin & Associates in the amount of $15,000 for cost of capital analysis The notice provides seven days for filing protests, which must be received by January 12, 2005

Thank you again for your efforts in responding to the Commission's solicitation

Jerry Lein
Public Utility Analyst
North Dakota Public Service Commission
600 E Boulevard Ave, Dept 408
Bismarck, ND 58501-0480
Telephone 701 328-2400
Fax. 701 328-2410

RECEIVED
JAN - 6 2005
NORTH DAKOTA PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Affidavit of Publication

Colleen Park, being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of:
PSC, Northern States Power, 1 time(s)
as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of ND

County of Burleigh

Subscribed and sworn to before me this 4 day of January 20 05.

Kim Arman

KIM ARMAN
Notary Public
State of North Dakota
My Commission Expires July 14, 2009

46 PU-04-578 Pages 1

Affidavit of Publication

by North Dakota Advertising Service, Inc

01/06/2005 C Comm Legal PUD (4) Mike ALJ

NDNA
NORTH DAKOTA NEWSPAPER ASSOCIATION

North Dakota Newspaper Association
1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

RECEIVED
JAN - 6
PUBLIC SERVICE COMMISSION
EXECUTIVE

INVOICE

Order **20035-04124PP2** Invoice # **49572**

January 5, 2005

Attn: ILLONAA. JEFFCOAT-SACCO
PUBLIC SERVICE COMMISSION
600 E. BOULEVARD AVE.
STATE CAPITOL
BISMARCK, ND 58505
Voice 701-328-4076

Advertiser **Public Utilities Division**

P.O.#

Amount Due **$171.47**

Amount Paid

Please detach and return this portion with your payment

Public Utilities Division Invoice # 20035-04124PP2-49572

Ad Size	*Rate Type*	*Rate*	*Total*	*Discount*	*(%)*	*Caption*	*Page*	*Run Date*
Fargo, The Forum (Fargo ND)								
121 00	SPR2	0 71	85 91	0 00		Northern States Power		12/27/04
Grand Forks Herald (Grand Forks ND)								
124 00	SPR2	0 69	85 56	0 00		Northern States Power		12/21/04

Gross Advertising	171 47	Total Misc	0.00	Amount Paid	0 00
Agency Discount		Tax	0 00	Adjustments	0 00
Other Discount	0 00	Total Billed	171 47	Payment Date	
Service Charge	0 00	Unbilled	0 00	Balance Due	171 47

46 **PU-04-578** Pages 1

Affidavit of Publication

by North Dakota Advertising Service, Inc

01/06/2005 C Comm Legal PUD (4) Mike ALJ

State Of North Dakota
Public Service Commission

Notice Of Hearing, Notice Of Public Input Sessions, And Notice Of Intervention Deadline

December 15, 2004

Case No. 04 - 578

Fargo	12 - 27
Grand Forks	12 - 21

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Wednesday, January 05, 2005 1 22 PM
To: Scott, Sandi L.
Subject: FW Notice of Intent to Award consulting services contract
Attachments: 1-5-05 Notice Award.DOC

Sandi,

Here's an e-mail Jerry sent on 04-578.

From: Lein, Jerry R.
Sent: Wednesday, January 05, 2005 12:55 PM
To: 'charlieking@snavely-king.com'; 'hlarkinjr@aol.com'; 'wdruin@usd.edu'; 'ajg@londoneconomics.com'; 'gregm@ggga.net'; 'ddittemore@cox.net'; 'fradigam@aol.com'; 'john@thorntonfinancial.org'; 'DMullinax@blueridgeecs.com'
Cc: Bendish, Annette M.; Helbling, Sharon D.; Jeffcoat-Sacco, Illona
Subject: Notice of Intent to Award consulting services contract

Thank you for responding to the Commission's recent RFP for consulting services A hardcopy is being mailed today of the attached Notice of Intent to Award a contract to Larkin & Associates in the amount of $15,000 for cost of capital analysis. The notice provides seven days for filing protests, which must be received by January 12, 2005.

Thank you again for your efforts in responding to the Commission's solicitation

Jerry Lein
Public Utility Analyst
North Dakota Public Service Commission
600 E Boulevard Ave, Dept 408
Bismarck, ND 58501-0480
Telephone· 701 328-2400
Fax. 701 328-2410

45 PU-04-578 Pages 1

E-mail to consulting services re notice of Award
by Public Service Commission

01/05/2005 C Comm Legal (PU-04) Mike ALJ

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY E-MAIL AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **5th day of January, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **eight** envelopes with first class postage, fully prepaid, securely sealed and containing a photocopy of

Notice of Intent to Award

The envelopes were addressed as follows:

John Thornton
Thornton Financial Consulting
7929 E Joshua Tree Ln
Scottsdale AZ 85250-7967
john@thorntonfinancial.org

Hugh Larkin
Larkin & Associates PLLC
15728 Farmington Rd
Livonia MI 48154
hlarkinjr@aol.com

Wade Druin
School of Business
University of South Dakota
414 E Clark St
Vermillion SD 57069-2390
wdruin@usd edu

Donna H Mullinax CPA
Blue Ridge Consulting Services Inc
2131 Woodruff Rd Ste 2100 PMB 309
Greenville SC 29607
dmullinax@blueridgecs com

Charles W King
Snavely King Majoros O'Connor & Lee Inc
1220 L St NW Ste 410
Washington D C 20005
charlieking@snavely-king.com

Gregory Lloyd Mann
Gorham Gold Greenwich & Associates
P O Box 23626
Overland KS 66283-0626
gregm@ggga net

44 PU-04-578 Pages 2
Affidavit of Service
By Public Service Commission
01/05/2005 C:\Documents\Legal\PUD\(4) Mike ALJ

Frank W Radigan
Hudson River Energy Group
120 Washington Ave
Albany NY 12210
fradigan@aol com

James M Proctor President
Free State Synergies
4803 Hallbrook Dr
Lawrence KS 66047
ddittemore@cox.net

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **5th day of January, 2005**.

Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

MOTION

January 5, 2005

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission issue a Notice of Intent to Award a contract to Larkin & Associates, PLLC in the amount of $15,000 for consulting services in Northern States Power Company's Natural Gas Rate Increase Application, Case No. PU-04-578.

JRL/sdh

43 PU 04-578 Pages 1
Motion to issue Notice of Intent to Award
Contract to Larkin & Associates
by Public Service Commission
01/05/2005 C:\Comm Legal\PUD (4) Mike.ACD

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Notice of Intent to Award

January 5, 2005

Dear Vendor

Thank you for your efforts in responding to the Commission's November 18, 2004 Request for Proposal (RFP) for consulting services relating to Northern States Power Company's (NSP) application for increased natural gas rates in North Dakota, Case No PU-04-578

The following vendors submitted proposals in response to the RFP:

- Larkin & Associates, PLLC
- Snavely King Majoros O'Connor & Lee, Inc
- University of South Dakota Business Research Bureau
- London Economics International LLC
- Free State Synergies
- Blue Ridge Consulting Services, Inc
- Hudson River Energy Group
- Thornton Financial Consulting
- Gorham, Gold, Greenwich & Associates

The Commission, by motion dated January 5, 2005, authorized issuance of a Notice of Intent to Award a contract to Larkin & Associates, PLLC in the amount of $15,000.00 for consulting services regarding NSP's cost of capital.

An interested party may protest this Notice by submitting a written description of the basis of the protest to the Commission within seven days after the date of this notice

The successful vendor is instructed not to begin work, purchase materials, or enter into subcontracts relating to the project until both the recipient and the State execute the contract

We appreciate your interest in doing business with the State of North Dakota and you will remain on our bidders list for future solicitations

Please contact me if you have any questions or comments

Sincerely,

Illona A. Jeffcoat-Sacco

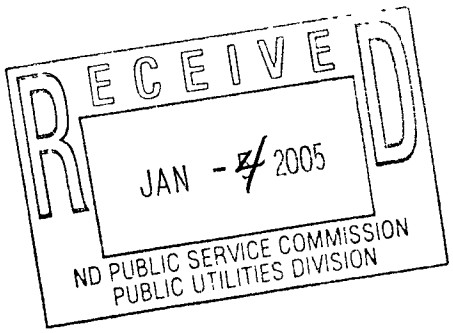
Illona A Jeffcoat-Sacco
Executive Secretary and Director of Public Utilities

Xcel Energy

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

January 4, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480



RE: INTERIM RATE TARIFF COMPLIANCE
CASE NO. PU-400-04-578

Dear Ms. Jeffcoat-Sacco:

Enclosed herewith are an original and one copy of our natural gas interim rate tariffs as approved by the Commission on December 1, 2004.

The only difference between these tariffs and those included in our November 2, 2004 interim petition is that we have removed the header pertaining to "proposed" tariffs, and we've added the order date to the bottom of each sheet. There remains in each tariff a section describing the interim rate adjustment.

Let me know if you have any other questions or comments regarding these tariffs.

Sincerely,

DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION & FINANCE
NORTHERN STATES POWER CO. D/B/A XCEL ENERGY

Enclosures

41 PU-04-578 Pages 7
Interim Rate Tariff Compliance
by Northern States Power Company by
1/04/2005 C Comm Legal PUD (4) Mike ACJ

RESIDENTIAL SERVICE
RATE CODE 401

Section No 5
3rd Revised Sheet No 1

AVAILABILITY
Available to any residential customer for domestic use of natural gas service

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	$5 50
Distribution Charge per Therm	$0 12480
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

COMMERCIAL AND INDUSTRIAL SERVICE Section No 5
RATE CODE 403 AND 410 3rd Revised Sheet No 2

AVAILABILITY
Available to any commercial and industrial customer for general use of natural gas service

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	$14 00
Distribution Charge per Therm	$0 11280
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

SMALL INTERRUPTIBLE SERVICE (Continued) Section No 5
RATE CODE 404 2nd Revised Sheet No 4

MONTHLY MINIMUM CHARGE
Basic Service Charge

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

LARGE INTERRUPTIBLE SERVICE Section No 5
RATE CODE 405 4th Revised Sheet No 5

AVAILABILITY
Available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$275 00
Distribution Charge per Therm	$0 04390
Cost of Gas Charge per Therm	Determined Monthly

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

(Continued on Sheet No 5-6)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
1st Revised Sheet No 10 2

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers Rules and regulations defining Company's obligation are set out in Section 6 of this rate book

ADDITIONAL FACILITIES

The cost of any new facilities required to provide service under this rate shall be borne by the customer

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located Company may refuse to accept delivery of gas which does not meet this quality standard

N

INTERIM RATE ADJUSTMENT N

A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE Section No 5
RATE CODE 415 2nd Revised Sheet No 13

AVAILABILITY
Available on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms

CHARACTER OF SERVICE
Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT
Customer's consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Customer Charge per Month	$300 00	
	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0 69600
Energy Charge per Therm	$0 00898	$0 03471

Unless otherwise agreed to, a five day notice of any change in the energy charge shall be provided

RESOURCE ADJUSTMENT
Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider The Company will revise the surcharge annually on the effective date of the True-up factor change

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

(Continued on Sheet No 5-13 1)

MEMORANDUM

To: File

Fr: Jerry Lein

Da: January 5, 2005

Re: Consultant Selection for NSP Rate Case No. PU-04-578

On November 18, 2004 the Commission issued a Request for Proposal with responses due by December 6th. Nine responses were received.

A Staff review team evaluated the proposals in accordance with the criteria set forth in the RFP. The Commission conducted a worksession on December 13th, during which the staff review team informed the Commission of its evaluation results. The team's top ranked proposal was from Larkin & Associates with a not-to-exceed price of $49,500 to address all issues and $15,000 to address only cost of capital. The second ranked proposal was from Snavely King with a not-to-exceed price of $51,053 to address all issues and $16,339 to address only cost of capital.

It was decided to pursue a contract with Larkin & Associates for assistance with cost of capital.

JRL

40 PU-04-578 Pages 1

Memo re Staff recommendation regarding consultants
by Public Service Commission

01/05/2004 C Comm Legal PUD (4) Mike ALJ

NORTH DAKOTA IVN INTERACTIVE VIDEO NETWORK

PO Box 8384
Grand Forks, ND 58202-8384
Phone 701-777-6354 Fax 701-777-6353

RECEIVED
DEC 27 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

INVOICE

DATE: 12/22/2004
INVOICE # 2463

Bill To:

Public Service Commission
600 E Boulevard Avenue, Dept 408
Bismarck, ND 58505-0480

Attn Sandi Scott

For:

Streaming
02/07/04
7 00-8 50pm

DESCRIPTION	HOURS	RATE	AMOUNT
Set up fee - $25 single event - $50 recurring events		25 00	25 00
Encode & Stream	1	3 50/hr	7 00
CD		20 00	20 00
		SUBTOTAL	$ 52 00
			-
		OTHER	-
		TOTAL	$ 52 00

Make all checks payable to University of North Dakota and mail to ND Interactive Video Network, PO Box 8384, Grand Forks, ND 58202-8384

THANK YOU FOR USING THE NORTH DA

Invoice for Encode & Streaming of Feb
7th IVN Public Input Session
By North Dakota Interactive Video Network

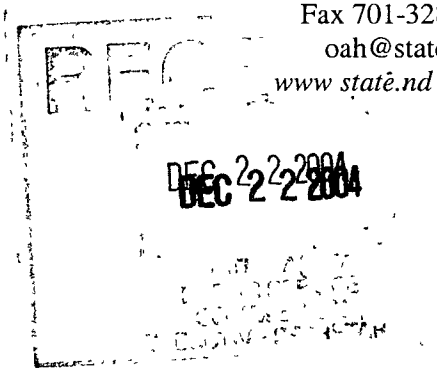
12/27/2004 C Comm Legal PUD (4) Mike ALJ

OFFICE OF ADMINISTRATIVE HEARINGS
STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
DIRECTOR

701-328-3260
Fax 701-328-3254
oah@state nd us
www state.nd us/oah

December 20, 2004



Mr. William Binek, Hearing Administrator
Public Service Commission
600 East Boulevard Avenue
Bismarck, ND 58505-0480

Dear Mr. Binek:

Thank you for your December 16, 2004, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matter of Northern States Power Company, Natural Gas Rate Increase Application (PU-04-578). I hereby designate myself to be assigned as an administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will be making the final administrative decision in regard to this matter (*i.e.*, agency head, deputy, board, commission) must be in attendance at the hearing.

Please send all additional relevant documents in regard to this matter (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Bismarck, North Dakota 58501-1882. I understand the hearing is scheduled for April 20, 2005, beginning at 1:30 p.m. and continuing on April 21, 2005, in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. Because the administrative law judge is requested to conduct the hearing only, the agency must give proper notice of the hearing.

Your request has been assigned OAH File No. 20040466. Please include this number on all future documents and correspondence filed for this matter with the Office of Administrative Hearings.

Sincerely,

Allen C. Hoberg
Director

ACH/eap

cc: Jim Johnson
Dave Sederquist

38 **PU-04-578** Pages 1

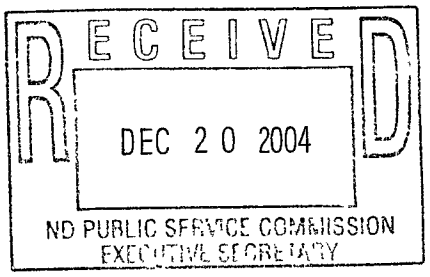
Allen Hoberg assigned Administrative Law Judge
by Office of Administrative Hearings
12/22/2004 (Comm Leca, PUD (4) Mike ALJ

WKG CONSULTANTS, INC.

1 Yorkville Way
West Windsor, New Jersey 08550

P O Box 463
Princeton Junction, New Jersey 08550

609 / 799-0057



December 15, 2004

Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Dear Ms. Jeffcoat-Sacco;

WKG Consultants, Inc. recently received your request for proposal for a consultant to assist in the Northern States Power rate case. We received the notification too late to respond because it was forwarded to us from another firm

Please place WKG Consultants, Inc. on your list of potential bidders for rate case assistance. We have considerable experience in tariff design, cost of service studies and the overall regulatory process for rate cases Our President, Mr William Gilstrap has almost 30 years' experience in rate cases including expert testimony for forecasting, construction management, tariff design and generation planning for electric utilities.

We also have conducted several studies to assist energy consumers in saving on energy costs Our work includes specific projects involving the assessment of the economic viability of wind power sites and other distributed generation projects.

Thank you for your assistance

Sincerely,

William Gilstrap
President, WKG Consultants, Inc.

37 PU-04-578 Pages 1

Notice they will not be filing a bid proposal

By WKG Consultants, Inc

12/20/2004 C Comm Legal PUD (4) Mike AL

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

December 16, 2004

Mr. Allen C. Hoberg
Office of Administrative Hearings
1707 North 9th Street, Lower Level
Bismarck, ND 58501

Re: Northern States Power Co.
Natural Gas Rate Increase
Application
Case No. PU-04-578

Dear Mr. Hoberg:

Enclosed is a request for an administrative law judge in the above case. The Commission has scheduled a hearing for April 20, 2005, beginning at 1:30 p.m. in the Commission's Hearing Room, 12th Floor, State Capitol, Bismarck. The administrative law judge will serve as a procedural law judge, a court reporter will be present, and the hearing will be tape recorded. A copy of the case is enclosed.

Please provide the Commission with a copy of any filings issued by your office in this matter.

If you have any questions, please contact me. Thank you.

Sincerely,

William W. Binek
Hearing Administrator

/sls
Enclosure

c. Jim Johnson, Northern States Power Co
Dave Sederquist, Northern States Power Co.

REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION

NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS
SFN 17819 (Rev 03-2001)

Name of Agency, Board, or Commission
Public Service Commission

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the hearing in Case No. PU-04-578, Northern States Power Co., Natural Gas Rate Increase Application Hearing set for April 20, 2005, beginning at 1.30 p.m. & continuing April 21st.

(e g., application of [name], appeal of [name], petition of [name]) Authority for the administrative action is found in Title 49 (North Dakota Century Code and/or North Dakota Administrative Code)

Please attach related documents and correspondence.

The administrative action is more fully described as follows.

It requests designation of an administrative law judge (please check one):

- ☐ **To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.**
- ☑ **To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).**
- ☐ **To conduct the hearing, issue findings of fact, conclusions of law, and a final order.**

PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact: (Attach separate list if necessary.)

AGENCY Public Service Commission	Address 600 E Blvd. Ave., Dept 408, Bismarck, ND 58505	Telephone Number 328-2400
Representation William W. Binek, Chief Counsel	Address Same as above	Telephone Number 328-4088
PARTY Northern States Power Co	Address 800 Nicollet Mall, Suite 2900, Minneapolis, MN 55401	Telephone Number 612-215-4592
Representation Jim Johnson, Counsel	Address Same as Above	Telephone Number 612-215-4592
PARTY Northern States Power Co.	Address P. O. Box 2747, Fargo, ND 58108-2747	Telephone Number 701-241-8632
Representation Dave Sederquist, Sr. Consultant	Address Same as above	Telephone Number 701-241-8632

Additional Comments
Hearing will be tape recorded and a court reporter will be present.

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of the notice.)

Typed or Printed Name and Title of Requesting Person	Date
William W. Binek, Hearing Administrator	12-16-04
Signature of Requesting Person X	

NORTH DAKOTA IVN
INTERACTIVE VIDEO NETWORK

CONFIRMATION

Confirmation - do not pay

PO Box 8384
Grand Forks, ND 58202-8384
Phone 701-777-6354 Fax 701-777-6353

DATE: 12/16/04

RECEIVED
DEC 16 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

ND Public Service Commission
600 E Boulevard Avenue, Dept 408
Bismarck, ND 58505-0480

Attn Sandi Scott

Date of Event 2/7/05
Time 7 00-8 50pm

Reservation # 8933

DESCRIPTION	HOURS	RATE	AMOUNT
Telephone Line Charge $80/hr	2	80 00	$ 160 00
Technical Charge $10/hr/site	2	20 00	40 00
Sites			
Host - Bsmck Public Library, NDSU EML 183, UND Gamble 120			
Administrative Fee per event		50 00	
Site Fee $25/site/event		25 00	
Long Distance Line Charge		80 00	
		SUBTOTAL	$ 200 00
			-
		OTHER	-
		TOTAL	$ 200 00

Maps of the sites can be found on http //ndivn nodak edu Click on Directory of Sites tab, the scroll down to Higher Ed Classroom maps

Events cancelled less than 24 hours before the event will be charged the administration and site fee
Sites dropped less than 24 hours before the event will be charged the

THANK YOU FOR USING THE NORTH DAKOTA I

34 **PU-04-578** Pages 2

Confirmation #8933 for IVN system for
Feb 7, 2005 Public Input Session
by North Dakota Interactive Video Network

2/16/2004 C Comm Legal PUD (4) Mike Al

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **16th day of December, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline

The envelopes were addressed as follows:

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747
Cert. No. 7003 2260 0001 3517 9244

Kent T Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Mineapolis MN 55401
Cert. No. 7003 2260 0001 3517 9251

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3517 9268

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **16th day of December, 2004**.

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **16th day of December, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

> **Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline**

The envelopes were addressed as follows.

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Subscribed and sworn to before me
this **16th day of December, 2004**

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

dhawk@simplot.com
David Hawk
J R Simplot
PO Box 27
Boise ID 83707-0027

rickstensby@clearchannel.com
KCJB, KRRZ AM and KMXA, KYYZ, KIZZ
PO Box 10
Minot ND 58702-0010

dickvoight@clearchannel.com
KFGO
Box 2966
Fargo ND 58102-2966

patmclean@clearchannel.com
KKXL AM and KKXL, KQHT, KJKJ, KSNR
PO Box 13598
Grand Forks ND 58208-3598

studio@literock105.com
KQWB, KPFX, KVOX, KLTA FM, KQWB AM Ra
PO Box 9919
Fargo ND 58106-9919

mail@kvlytv11.com
KXJB-TV 4
4302 13th Ave S
Fargo ND 58103-3313

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

don.ball@mdu.com
Don Ball
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

karen.collins@mdu.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

mdickerson@state.nd.us
Marcy Dickerson
State Tax Department
State Capitol
Bismarck ND 58505

alaamodt@wday.com
WDAY AM-FM & TV
PO Box 2466
Fargo ND 58108-2466

news@wdaz.com
WDAZ-TV
PO Box 12639
Grand Forks ND 58208-2639

mark.nisbet@xcelenergy.com
Mark Nisbet
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

dave.sederquist@xcelenergy.com
Dave Sederquist
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

F James Moriarty
2333 Plum Grove Dr
O'Fallon MO 63366

Steven Tomac
2498 59th St
St Anthony ND 58566-9640

Will Kaul
Cooperative Power Association
P O Box 800
Elk River MN 55330-0800

Laurie Baranko
Dakota Resource Council
PO Box 1095
Dickinson ND 58602-1095

Jerry Tuchscherer
Grand Forks Board of Realtors
1407 24th Ave S #340
Grand Forks ND 58201-6761

Frank Morehouse
Great Plains Natural Gas Co
PO Box 176
Fergus Falls MN 56548-0176

Jay Casler
INDEPTH DATA INC
44 S Bdwy 18th Fl
White Plains NY 10601-4425

Karyn Grass
IPAMS
6620 Denver Club Bldg 518 17th St
Denver CO 80202-4167

KHRT AM
PO Box 1210
Minot ND 58702-1210

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KNOX-AM & KRRK-FM
PO Box 13638
Grand Forks ND 58208-3638

KTHI-TV
PO Box 12427
Grand Forks ND 58208-2427

Bruce Imsdahl
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

Mike Foley
NARUC
1101 Vermont Avenue NW Ste 200
Washington DC 20005

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
PO Box 6808
Falls Church VA 22046-6808

Scott Speaker
Natural Gas Week
1401 New York Ave NW Ste 500
Washington DC 20005-2150

Harlan Fuglesten
ND Association of RECs
PO Box 727
Mandan ND 58554-0727

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

Helbling, Sharon D.

From: Helbling, Sharon D
Sent: Wednesday, December 15, 2004 2 16 PM
To: ndna
Subject: Notice of Hearing, Notice of Public Input Sessions, and Notice of Interention Deadline, Case No PU-04-578

Colleen Park
North Dakota Newspaper Association

Colleen:

Please have the attached Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention published as a legal publication in the next issue of the following newspapers:

Grand Forks Herald
Fargo Forum

Please run it as a "News Item Only" article as well, and send the bill to the Public Service Commission along with a tear sheet for billing purposes.

If you have any questions, please call me at 328-4076, or e-mail me

Thank you

Sharon Helbling
Public Utilities Division



12-15-04
of Hearing

1

32 **PU-04-578** Pages 1

Notice e-mailed to NDNA requesting publication
by Public Service Commission

12/15/2004 C Comm Legal PUD (4) Mike ALJ

APPROVED

DATE: 12-15-04

KME

MOTION

December 15, 2004

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission issue a Notice of Hearing, Notice of Public Input Sessions, and Notice of Intervention Deadline in Northern States Power Company's Natural Gas Rate Increase application, Case No. PU-04-578

MRD

31 PU-04-578 Pages 1

Motion scheduling hearing and public input sessions by Public Service Commission

12/15/2004 C Comm Legal PUD (4) Mike ALJ

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power company
Natural Gas Rate Increase
Application

Case No. PU-04-578

NOTICE OF HEARING, NOTICE OF PUBLIC INPUT SESSIONS, AND NOTICE OF INTERVENTION DEADLINE

December 15, 2004

On November 2, 2004, Northern States Power Company (NSP) filed an application to increase its rates for natural gas service by an amount sufficient to provide increased total annual revenue of $1,280,232. NSP proposes to change natural gas rates for residential customers by increasing the Basic Service Charge per month from $5.50 to $8.50 and by decreasing the Distribution Charge per therm from $0 12480 to $0.12388 NSP proposes to increase natural gas rates to small interruptible customers by increasing the Distribution Charge per therm from $0.07310 to $0 07740. NSP proposes to increase natural gas rates to large interruptible customers by increasing the Distribution Charge per therm from $0.04390 to $0.04632. NSP proposes to change natural gas rates to commercial and industrial service customers by changing the Basic Service Charge per month from $14 00 to $20.00 and changing the Distribution Charge per therm from $0.11280 to $0 10120. Residential, commercial, and industrial customers will be able to determine whether their bill will change by reviewing their gas usage throughout the year

NSP anticipates that an average residential customer bill will increase by $2-$3 per month. NSP further proposes a rate element for residential customers in order to capture what natural gas customers would have paid toward recovery of distribution costs had weather-normalized use not deviated from the sales volume established in the rate proceeding. NSP's proposed rate changes would not affect the cost of purchased gas, which is separately recovered through the Cost of Gas billing provision.

A **public hearing** on this matter will be held beginning **April 20, 2005 at 1:30 p.m. CDT** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505. You can listen to a broadcast of the hearing on the Commission's website at http //www psc state nd us/psc/media/comm-live.html.

Issues to be considered in this matter include

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

2 What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

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

4 What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

5 Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6 Other relevant information or proposals concerning the proceeding

Anyone wishing to become a party to this proceeding must file a **Petition to Intervene by January 31, 2005**.

A Public Input Session will be held via interactive television on **February 7, 2005, at 7 p.m. CST** at locations set forth below. Members of the public are invited to appear and participate in the informal discussion The session is not considered part of the technical hearing and the discussion at the session will not become part of the evidence reviewed by the Commission in making its decision. The discussion will, however, aid the Commission and its staff in identifying areas of concern to the members of the public and help customers better understand NSP's request

Public Input Session Locations

Bismarck Bismarck Veterans Memorial Public Library 515 North 5th Street, Lower Level Bismarck, ND	**Fargo** North Dakota State University E Morrow Lebedeff, Room 183 Fargo, ND
Grand Forks University of North Dakota Gamble Hall, Room 120 Grand Forks, ND	

The public will also be able to hear the input session by connecting to the Commission's web site www psc state nd us and clicking on "Highlighted Issues" and then clicking on the "Broadcast of Public Input Sessions" link. The Commission will receive e-mail questions during the session at ndpsc@state nd us

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400 or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials, please notify, Illona Jeffcoat-Sacco, Executive Secretary, at least 24 hours prior.

PUBLIC SERVICE COMMISSION

Susan E. Wefald	**Tony Clark**	**Kevin Cramer**
Commissioner	**President**	**Commissioner**

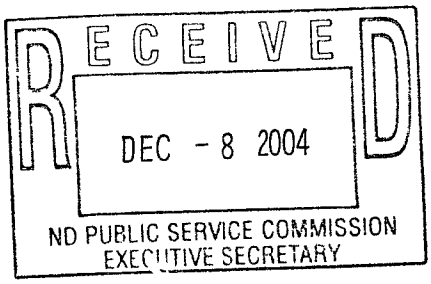
29 **PU-04-578** Pages 1

Notification that they will not be filing a response to RFP
By Berkshire Consulting Services

12/09/2004 CC Corr Legal PUD (4) Mike

Scott, Sandi L.

From: Scheduling [ivn scheduling@ivn.nodak edu]
Sent: Wednesday, December 08, 2004 1.22 PM
To: Scott, Sandi L , june piper@ivn nodak edu; marshall.samuelson@ivn nodak.edu
Subject: RE Videoconferencing Web Streaming Request
Attachments: Streaming Public Input Session 2-7-05 xls



PU-04-573 Pages 2

Video conferencing Web Streaming
Confirmation
by North Dakota Interactive Video Network

12/8/2004 Comm Legal PUD (4) Mike

12/8/2004

NORTH DAKOTA IVN INTERACTIVE VIDEO NETWORK

Videoconferencing Web Streaming Request

Date of Request: December 7, 2004 **Submit at least 2 business days prior to event.**

CUSTOMER INFORMATION

Name of person submitting request: Sandi Scott

Phone: 701-328-4081 **e-mail:** slscott@state.nd.us

Organization: North Dakota Public Service Commission

Dept. Name:

Event Facilitator/Instructor's Name:

Phone: 701-328-4081 **e-mail:** slscott@state.nd.us

RECEIVED
DEC - 8 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Billing Address: 600 E Blvd Ave , Dept. 408, Bismarck, ND 58505-0480

EVENT AND SERVICE FEE INFORMATION

Reservation Number 8933 **Conference Number:**

Starbak Port: (for office use only) *(confirms request)* Starbak Port 5

If a Course, Name and Number

If a meeting, Title of meeting: NSP Natural Gas Rate Increase Public Input Session, Case No PU-04-578

For recurring events complete the following:

Start Date: **Stop Date:**

Day of the week. M [ ] T [ ] W [ ] R [ ] F [ ] S [ ]

Start Time: AM/PM **End Time AM/PM**

For one time event, complete the following:

Date: February 7, 2005

Start Time: AM/PM 7 p m. **End Time: AM/PM** 8.50 p m.

Total Number of Hours: two

TYPE OF EVENT -- CHECK ONE

[X] One time event - Set-up fee $25

[ ] Recurring event - Set-up fee $50 (scheduled at one time)

Services: - Check those that apply to your event

[ ] Encode and stream a live event $3.50 per hour with NO archive

[X] Encode and stream a live event at $3.50 per hour and archive for 10 business days
After 10 business days, the event will be removed from the IVN server

Additional Services:

[X] Provide CD/DVD of event for $20 per copy

[ ] Requestor. If you want a password for viewing or access, provide it here
No longer than 6 characters or words, case sensitive

NOTE. Confirmation of streaming will be sent to requestor. Instructions for viewing a streamed event can be found at http://www.ndivn.nodak.edu **Scroll to Services, click on Streaming, then click on Viewing Instructions in box on the left Please forward those instructions or web address to your participants.**

e-mail this form to: scheduling@mail.und.nodak edu

Effective Sept 1, 2004

Scott, Sandi L.

From: Scott, Sandi L
Sent: Tuesday, December 07, 2004 8 22 AM
To: ivn scheduling@ivn nodak edu
Cc: Scott, Sandi L
Subject: Videoconferencing Web Streaming Request
Attachments: streamform xls

Hi Sandi,

Attached is the Public Service Commission's Videoconferencing Web Streaming Request for the Public Input Session, scheduled for Feb 7, 2005 (Reservation # 8933) If you have any questions, please call me at 328-4081

Thank you for all of your help through this process

Sandi Scott
ND Public Service Commission
600 E Blvd Ave , Dept 408
Bismarck, ND 58505-0480
Telephone, 701-328-4081
Fax 701-328-2410
E-Mail Address slscott@state nd us

27 PU-04-578 Page 1

E-mail to ND [illegible] Videoconferencing Web Streaming Request
To Public Service Commission

Videoconferencing Web Streaming Request

Date of Request: December 7, 2004 **Submit at least 2 business days prior to event.**

CUSTOMER INFORMATION

Name of person submitting request: Sandi Scott

Phone: 701-328-4081 **e-mail:** slscott@state.nd.us

Organization: North Dakota Public Service Commission

Dept. Name:

Event Facilitator/Instructor's Name:

Phone: 701-328-4081 **e-mail:** slscott@state.nd.us

Billing Address: 600 E Blvd Ave , Dept 408, Bismarck, ND 58505-0480

EVENT AND SERVICE FEE INFORMATION

Reservation Number 8933 **Conference Number:**

Starbak Port: (for office use only) *(confirms request)*

If a Course, Name and Number

If a meeting, Title of meeting: NSP Natural Gas Rate Increase Public Input Session, Case No PU-04-578

For recurring events complete the following:

Start Date: **Stop Date:**

Day of the week: M [ ] T [ ] W [ ] R [ ] F [ ] S [ ]

Start Time: AM/PM **End Time AM/PM**

For one time event, complete the following:

Date: February 7, 2005

Start Time: AM/PM 7 p m **End Time: AM/PM** 8 50 p m

Total Number of Hours: two

TYPE OF EVENT – CHECK ONE

[X] One time event - Set-up fee $25

[ ] Recurring event - Set-up fee $50 (scheduled at one time)

Services: - Check those that apply to your event

[ ] Encode and stream a live event $3 50 per hour with NO archive

[X] Encode and stream a live event at $3 50 per hour and archive for 10 business days
After 10 business days, the event will be removed from the IVN server

Additional Services:

[X] Provide CD/DVD of event for $20 per copy

[ ] Requestor If you want a password for viewing or access, provide it here.
No longer than 6 characters or words, case sensitive

NOTE: Confirmation of streaming will be sent to requestor. Instructions for viewing a streamed event can be found at http://www.ndivn.nodak.edu **Scroll to Services, click on Streaming, then click on Viewing Instructions in box on the left. Please forward those instructions or web address to your participants.**

e-mail this form to: scheduling@mail.und.nodak.edu

Videoconferencing Web Streaming Request
by Public Service Commission
12/07/2004 CC Comm Legal PUD (4) Mike

NORTH DAKOTA IVN INTERACTIVE VIDEO NETWORK

2004 Meeting Schedul..g Form

Parts highlighted in yellow are required information.

RECEIVED
DEC - 6 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Reservation Number (s) 8933
Date Requested: November 22, 2004

Requested by & Address:
ND Public Service Commission
600 E. Blvd. Ave. Dept. 408
Bismarck, ND 58505-0480

Phone: 701-328-4081

E-mail Address: slscott@state.nd.us

TITLE OF EVENT: Public Input Session, Case No. PU-04-578, Northern States Power Co., Natural Gas Rate Increase, Application

NOTE List all times in Central Standard Time

Preferred Date	Day of the Week	Start Time AM/PM	End Time AM/PM
February 7, 2005	Monday	7:00pm	8:50pm

SITES: Identify host site with an H; identify all receiving sites with an X. Note: Limit of 12 Sites

HIGHER ED SITES

Bismarck- Bismarck State College		Jamestown State Hospital	
Bottineau – MiSU Bottineau		Mayville – Mayville State Univ.	
Devils Lake – Lake Region State College		Minot – Minot State Univ.	
Dickinson – Dickinson State Univ.		Valley City – Valley City State Univ.	
Fargo – NDSU EML 183	X	Wahpeton – ND State College of Science	
Grand Forks – UND Gamble 120	X	Williston – Williston State College	

TRIBAL COLLEGES

Belcourt-Turtle Mt CC		Fort Yates – Sitting Bull College	
Bismarck-United Tribes Tech		McLaughlin, SD – Sitting Bull College	
Fort Totten - CCCC		New Town – Ft. Berthold Community College	

If you wish to use sites other than higher ed, first you need to contact the site to check for its availability. List the site below with name of city first followed by site name. A listing of other sites can be found on the IVN website at www.ndivn.nodak.edu under Site Information, Directory of Sites

For other sites list city first then, site name (i.e.building name and room number)

OTHER SITES	ROOM PHONE NUMBER	ROOM FAX NUMBER
Bismarck Public Library Host		

NOTE: It is the responsibility of the individual requesting the meeting/class to obtain the ROOM PHONE and ROOM FAX numbers of the other sites.

Event Facilitator: Public Service Commission
Phone: 701-328-4081 **E-mail Address: slscott@state.nd.us**

Check Resources Needed – NOTE: not all sites have audio/visual equipment listed below.

VCR : X	DVD:	Document Camera:	Laptop Computer:	Guest Speaker:

Billing:

	C: NDUS Users – Classes & Meetings	**F: Non-Profit Groups** - $80/hour + 10/hour/site + Admin fee $50 + $25/site	
	D: NDUS Grants/Fees/Campus Membership - $80/hour + $10/hour/site	**G: Tribal Colleges** – per agreement	
X	**E: State Gov't/Political Subdivisions/K-12** $80/hour + $10/hour/site	**H: Multi-state Conference** –Admin Fee - $50. Other applicable charges depending upon type of connection and sites involved	

**** STREAMED EVENT**

WORD/Forms **E-mail form to scheduling@mail.und.nodak.edu**

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Proposal

by London Economics International LLC

12/06/2004 CC Comm Legal PUD (4) Mike

22 PU-04-578 Pages 44

Proposal

by Business Research Bureau

12/06/2004 CC Comm Legal PUD (4) Mike

23 PU-04-578 Pages 50

Proposal

by Sea Ridge Consulting Services Inc

12/06/2004 CC Comm Legal PUD (4) Mike

24 PU-04-578 Pages 3

Proposal

by Larkin & Associates

12/06/2004 CC Comm Legal PUD (4) Mike

16 **PU-04-578** Pages 42

Proposal

by Snavely King Majoros O'Connor & Lee Inc

12/03/2004 CC Comm Legal PUD (4) Mike

17 **PU-04-578** Pages 1

Cover letter re Proposal

by Snavely King Majoros O'Connor & Lee Inc

12/03/2004 CC Comm Legal PUD (4) Mike

18 **PU-04-578** Pages 62

Proposal

by Gorham Gold Greenwich & Associates

12/03/2004 CC Comm Legal PUD (4) Mike

19 **PU-04-578** Pages 23

Proposal

by Hudson River Energy Group

12/03/2004 CC Comm Legal PUD (4) Mike

20 **PU-04-578** Pages 27

Proposal

by Free State Synergies

12/03/2004 CC Comm Legal PUD (4) Mike

Xcel Energy℠

2302 Great Northern Drive
PO Box 2747
Fargo, ND 58108-2747

Gas Utility
State of North Dakota

Prefiled Direct Testimony

Case No. PU-400-04-578



Submitted
December 1, 2004

15 PU-04-578 Pages 15
Prefiled Direct Testimony
By Northern States Power Company
12/01/2004 CC Comm Legal PUD (4) Mike



2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

December 1, 2004

Ms. Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Northern States Power Company d/b/a Xcel Energy
Case No. PU-400-04-578
Pre-filed Direct Testimony

Dear Ms. Jeffcoat-Sacco:

On November 2, 2004, pursuant to North Dakota Century Code ("N.D.C.C.") § 49-05-05, Northern States Power Company d/b/a Xcel Energy ("the Company" or "Xcel Energy") filed a Notice of Change in Rates for Natural Gas Service ("Notice"). The Notice proposed an increase in the natural gas rates stated in the Company's North Dakota Gas Rate Book of $1.3 million or 1.8% annually. The Notice included changes to certain tariff terms and conditions of service. Also, the Company filed an Alternative Petition for Interim Rates, in the event the Commission suspended the general Notice of Change in Rates. Pursuant to N.D.C.C. § 49-05-06, Subd. 2, interim rates will be effective January 1, 2005.

Pursuant to the procedural schedule agreed to with Commission Staff, the Company hereby submits an original and seven (7) copies of it Direct Testimony and Exhibits in support of the Notice. The direct testimony is organized as follows:

Tab	Witness	Subject of Testimony
1	Kent T. Larson	Policy
2	Jeffrey C. Robinson	Revenue Requirements
3	Nicholas Paluck	Class Cost of Service and Rate Design
4	Dr. Karl A. McDermott	Cost of Equity

The test year is the twelve-month period ending December 31, 2004, which is a "current test year" period (pursuant to N.D.C.C. § 49-05-04.1) ending not later than twelve months after the date the new rate schedules were filed on November 2, 2004. The Company is including a copy of the applicable portions of its 2003 jurisdictional annual report to the Commission

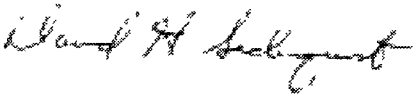
(filed in May 2004) as an exhibit to the testimony of Mr. Robinson to satisfy the requirement to file actual data for the twelve-month period immediately preceding the test year selected.

As agreed with the Commission Staff, the Company is submitting the testimony by email today, and will send the bound paper copies by overnight courier.

Please note that the signed affidavit for one of the witness, Mr. Kent T. Larson, will be forwarded to the Commission shortly under separate cover.

Please address any questions regarding this submittal to Mr. Dave Sederquist at (701) 241-8632 or Mr. Jim Johnson at (612) 215-4592.

Sincerely,



David H. Sederquist
Sr. Consultant, Regulation & Finance
Northern States Power Co. d/b/a Xcel Energy

Enclosures

Direct Testimony and Schedules
Kent T. Larson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company
d/b/a Xcel Energy
Notice of Change in Rates
For Natural Gas Service

Case No. PU-400-04-578
Exhibit___

Policy Testimony

December 1, 2004

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. I am Kent T. Larson, Vice-President, Jurisdictional Relations for Xcel Energy Inc. I am employed by Xcel Energy Services Inc. ("XES"), the service company for Xcel Energy Inc. My office is at 414 Nicollet Mall Minneapolis, Minnesota, 55401. My resume is included as Exhibit___(KTL-1), Schedule 1.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. From 1997 to 2000, I was Chief Executive and Managing Director, Dakotas for Northern States Power Company, and in 2001, I was named State Vice President for Minnesota and the Dakotas for XES. I became Vice President of Jurisdictional Relations in 2004, with varying levels of responsibility for governmental, regulatory, and community affairs in ten of the states served by the Xcel Energy Inc. operating companies. In all the positions I have held since 1997 except for a one-year period, I have had management responsibility for public affairs and jurisdictional financial results for the natural gas and electric utility operations in North Dakota.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or the "Company" and where easier for purposes of clarity, "NSP"). NSP d/b/a Xcel Energy is the utility operating company subsidiary formed as part of the Xcel Energy Inc. merger that provides natural gas and electric service in North Dakota, South Dakota and Minnesota.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will summarize the need for a base natural gas rate increase and introduce the other Company-sponsored witnesses and exhibits. In doing so, I will briefly describe our North Dakota gas operations and the primary cost drivers in this case, and how the Company has prudently managed its business since the last natural gas rate case (Case No. PU-400-00-521).

Q. ARE YOU MAKING ANY RECOMMENDATIONS FOR THE COMMISSION TO CONSIDER IN THIS PROCEEDING?

A. Yes. In addition to granting the requested increase in natural gas distribution revenues, I recommend that the Commission address some significant changes that have occurred in the Company's gas utility business in North Dakota. Specifically, I recommend that the Commission approve one of the rate design alternatives being proposed to help manage the volatility in both customer bills and Company revenues. Mr. Nicholas Paluck discusses these approaches in more detail.

This volatility has several root causes. For our customers, wholesale natural gas commodity prices are two to three times higher than they were just five years ago, and winter wholesale prices this past heating season hit new highs – reaching $12/Dekatherm ("Dkt"). This dramatic price increase has resulted in increased retail rates through the Gas Cost Adjustment and accelerated a historic trend of steadily declining average use per residential customer, making it difficult for the Company to maintain earnings at or near its allowed return on equity ("ROE").

Xcel Energy certainly encourages customers to use natural gas wisely and efficiently. As such, we do not want to discourage the conservation and efficiency efforts that result in declining use per customer. Rather, to assist customers in managing the volatility of their bills while ensuring the Company a fair opportunity to earn a reasonable return, the Commission should consider adopting proposals that, as a package, will support the objective of reducing both rate and revenue volatility in the current natural gas environment.

II. CASE OVERVIEW

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company requires a rate increase of $1,280,000 or 1.8 percent in order to recover our prudent costs of service and a reasonable rate of return. While we have exercised prudent and effective management over time, we cannot offset the trends of increasing costs and declining use per customer at current rates. Thus, this rate increase is needed to return the gas operations to a reasonable and fair rate of return, based on a 2004 budget test year.

We propose to recover costs through a rate design that fairly and appropriately allocates costs to the various customer classes and helps mitigate the impacts of price and bill volatility for customers. These initiatives will benefit both customers and the Company over time through increased stability.

The changes in the industry over the past few years have been significant. This rate case offers a good opportunity to address these issues, since the

overall requested rate increase is relatively small. Therefore, the Company respectfully requests that the Commission approve:

- Our requested rate increase of 1.8 percent;
- An overall rate of return of 9.43 percent, which includes a rate of return on equity of 11.5 percent, the same return on equity authorized in the most recent gas rate case in 2000; and
- Our proposed rate design and tariffs.

III. INTRODUCTION OF WITNESSES

Q. PLEASE REVIEW THE WITNESSES THE COMPANY IS SPONSORING IN THIS PROCEEDING.

A. In addition to my Policy Testimony, the Company sponsors the following witnesses:

- *Jeffrey C. Robinson*, who sponsors the overall revenue requirement for the case. Mr. Robinson sponsors the schedules supporting our income statement, rate base, revenue deficiency, test year capital structure and jurisdictional allocations.
- *Nicholas Paluck*, who sponsors the class cost of service study and our rate design proposals and tariff sheets.
- *Dr. Karl A. McDermott* of NERA Economic Consulting, who sponsors testimony on the appropriate cost of common equity.

I would note that Dr. McDermott calculates a cost of common equity of 11.55 percent. However, the Company is requesting that the Commission grant a slightly lower authorized return on equity of 11.5 percent -- the same ROE established in the Company's most recent gas rate case -- for purposes of

setting rates. Mr. Robinson uses the Company's recommended 11.5 percent ROE to calculate the test year revenue requirement and revenue deficiency. An authorized ROE of 11.5 percent will also minimize the impact of any rate adjustments necessary to implement final rates, since interim rates also reflect an 11.5 percent ROE.

IV. NEED FOR RATE INCREASE

Q. COULD YOU PLEASE DESCRIBE THE ORGANIZATIONAL STRUCTURE OF WHICH THE NSP NATURAL GAS UTILITY OPERATION IN NORTH DAKOTA IS A PART?

A. Yes. NSP is a first tier subsidiary of Xcel Energy Inc., a registered holding company under the Public Utility Holding Company Act ("PUHCA") formed by the merger of Old NSP and New Century Energies, Inc., approved by the Commission in Docket No. PU-400-99-418. Exhibit___(KTL-1), Schedule 2 is an organizational chart showing how NSP fits into to the overall corporate structure of Xcel Energy Inc. NSP offers natural gas and/or electric service to customers in North Dakota, South Dakota, and Minnesota.

In addition to being a newly formed first tier subsidiary of a registered holding company parent, there are two other main organizational changes since the test year in our last gas rate case in 2000. First, most shared expenses originate on the books of Xcel Energy Services Inc. ("XES" or the "Service Company") and are directly assigned or allocated to the utility operating companies, including NSP. Second, the gas utility operation is no longer a separate business unit within NSP; instead, most functions of the gas utility operation

are jointly managed with our retail electric utility operation through the Customer & Field Operations business unit.

Q. COULD YOU PLEASE DESCRIBE THE NSP NATURAL GAS UTILITY BUSINESS?

A. Yes. Today the NSP natural gas utility business serves approximately 435,000 customers. Of these, about 41,000 customers are located in North Dakota in the cities of Fargo, Grand Forks, and several surrounding communities, including West Fargo, Mapleton, Buffalo, Casselton, Emerado, Fargo, Grand Forks, Horace, Mapleton, Oriska, Prairie Rose, Reile's Acres, Riverside, Tower City, Thompson, West Fargo, and Wild Rice. About eighty five percent of our North Dakota customers are in the Residential class, and fifteen percent are in the Commercial and Industrial classes. Approximately 70 percent of our annual sales are Firm sales, with approximately 30 percent being Interruptible sales to larger customers with alternate fuel capability.

Xcel Energy has 31 employees dedicated to North Dakota gas operations, with 72 additional management, business office, and gas operations support personnel located in the Fargo and Grand Forks service centers. The North Dakota gas operation is also supported by NSP operational and Service Company (corporate) employees located in Minnesota, Wisconsin, and Colorado.

Xcel Energy's North Dakota gas distribution system is connected directly to the interstate pipeline systems of Viking Gas Transmission Company ("Viking") and Williston Basin Interstate Pipeline Company ("WBI"), two non-affiliated pipelines regulated by the Federal Energy Regulatory Commission ("FERC"). However, the Company uses upstream transportation

and underground storage services on several interstate (e.g., Northern Natural Gas Company, ANR Pipeline Company, Northern Border Pipeline) and Canadian gas pipelines (e.g., TransCanada) to deliver natural gas to our retail gas customers in North Dakota.

Q. HOW LONG HAS IT BEEN SINCE THE COMPANY'S LAST BASE RATE INCREASE FOR ITS GAS DISTRIBUTION OPERATIONS IN NORTH DAKOTA?

A. The Commission approved a $500,000 (1.2%) gas base rate increase in 2001 (Case No. PU-400-00-521). In that case, the Company was also allowed to amortize and recover over 8 years the costs of cleaning up an old manufactured gas plant ("MGP") site in Grand Forks through the Cost of Gas rider in our tariffs, with a recovery of $360,000 per year.

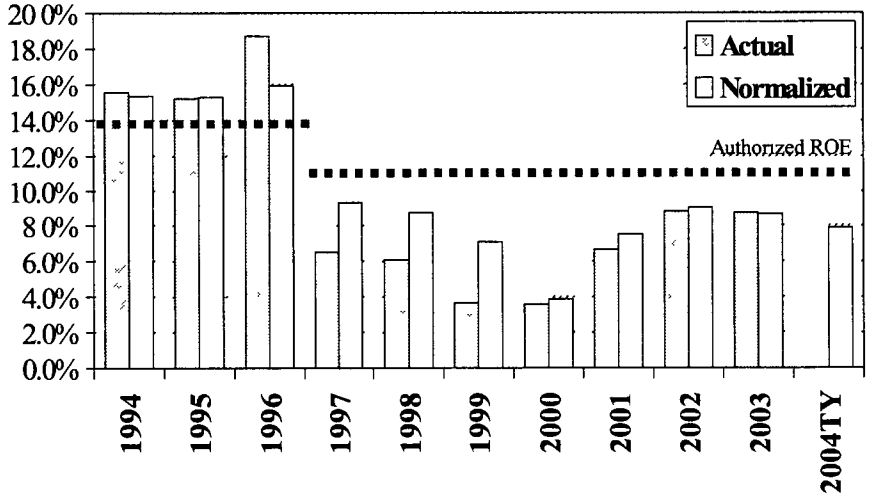
Prior to the 2000 case, Xcel Energy had implemented a $491,000 base gas rate *reduction* in 1996, following a staff earnings review and investigation. Due to the offsetting nature of the 1996 and 2000 rate changes, the Company's current base distribution rates have not changed appreciably, overall, since its 1984 general rate filing in Case No. 10,523.

Q. WHAT HAS BEEN THE EARNINGS HISTORY OF XCEL ENERGY'S NORTH DAKOTA GAS OPERATIONS?

A. Since 1997, the year in which the most devastating Red River flood in recorded history damaged over half of the Company's gas distribution system in the Grand Forks area, the Company has earned annual returns on equity ("ROE") in the range of 3.7% -- 8.5%. Chart 1 shows the 10 year history of actual and weather-adjusted earnings for our North Dakota gas operations, as reported to the Commission in our annually filed Jurisdictional Earnings Report.

CHART KTL-1

ND Gas Return on Equity



* Normalized adjusted for weather and Cost of Gas recovery timing

Q. IS SUCH A RANGE OF RETURNS ACCEPTABLE FOR CONTINUED SUCCESSFUL OPERATIONS OF A NATURAL GAS UTILITY?

A. No. Such returns are significantly below authorized levels, detrimental to the Company's financial health, and hinder Xcel Energy's ability to attract the capital needed to provide reliable, high-quality service to customers. A base rate increase is essential to allow the Company to recover prudently incurred costs and achieve a reasonable rate of return necessary to attract capital for investments in our North Dakota gas distribution operations.

Q. WHAT HAS THE COMPANY DONE TO MITIGATE THE NEED FOR A GENERAL RATE INCREASE?

A. I am pleased to report that compared to our last rate case test year four years ago, our operation and maintenance ("O&M") and property tax expenses have remained essentially flat, despite overall inflation during the period of approximately 9.7 percent (based on the Consumer Price Index). However, during the same period, our gas plant investments (rate base) and depreciation expense have grown significantly due mainly to the customer growth in two of the largest and most economically viable cities in the state. In addition, the Company has undertaken various system upgrade and reconstruction projects in recent years, and Xcel Energy Inc. has invested in information technologies ("IT") to control operating expenses. For example, the Company invested about $2.8 million in 2003 and 2004 on new mains and services, and $1.7 million for reconstruction. Of this latter amount, the company spent about $1.5 million on a gas pipeline relocation project along Main Avenue in Fargo which was required to accommodate a North Dakota Department of Transportation upgrade of that major thoroughfare in the northwest section of the city. Mr. Robinson discusses the new customer billing system, one of the major IT projects.

Our ability to earn our authorized return has also been impacted by, among other things, the industry-wide trend of declining use per customer. From 1996 to 2003, total retail gas usage per customer in North Dakota (normalized for weather) has decreased, on average, 2.2% annually as shown on Exhibit___(KTL-1), Schedule 3. Unlike the electric industry, where new electric technologies (e.g., computers, digital electronics) and increased saturation levels for existing technologies (e.g., central air conditioning) have caused use per customer to grow slowly but significantly over the years, the Company's natural gas distribution system largely serves the same uses as twenty years ago: space heating, water heating, and commercial process uses. While growth in the number of natural gas customers helped bolster annual earnings over the period, the decline in use per customer has considerably offset that customer growth.

Our successful efforts to manage costs have not been enough to offset this trend in declining usage, leading to chronic cost recovery shortfalls and inadequate returns. In addition, the Company's North Dakota service area experienced a series of warmer than normal weather over the period since 1997, with only one year (2003) with "near normal" heating degree days. This weather volatility adds to the need for changes in our gas pricing structure, as described by Mr. Paluck.

V. MANAGING VOLATILITY

Q. WHAT IS THE MOST SIGNIFICANT CHALLENGE FACING THE COMPANY AND ITS CUSTOMERS AT THIS TIME WITH REGARDS TO THE NORTH DAKOTA NATURAL GAS OPERATION?

A. At the time of the 2000 gas rate case filing, the wholesale gas commodity market was just starting to experience significant price increases and supply price volatility, in part driven by the California energy crisis of 2000. Rather than a return to pre-2000 conditions, we have seen further increases and volatility in wholesale commodity gas prices over the past several years, which in turn have had significant impacts on customers' bills and related impacts on Company earnings. Therefore, I would say that the biggest challenge facing the Company's gas utility business is how to effectively manage price volatility for our customers and to mitigate its impact on the Company while maintaining natural gas as a competitive fuel desirable to both residential and business customers.

Q. WHAT ACTIONS HAS THE COMPANY TAKEN THAT HAVE HELPED MINIMIZE THE IMPACT OF WHOLESALE COMMODITY PRICE RISK FOR ITS CUSTOMERS IN THIS VOLATILE NATURAL GAS MARKET?

A. The Company has made several decisions that have effectively provided it with significant options in designing its supply portfolio by leveraging the market to the greatest extent possible. For example, NSP holds firm transportation capacity on five major pipelines that provide access to the major supply basins in the Mid-Continent and Rocky Mountain areas of the U.S. and to the Alberta supply basin in Canada. This diversity ensures access to supplies throughout North America's most prolific production areas.

The Company's significant peak-shaving reserves are combined with contract underground storage capacity to provide assurance of winter supply deliverability and also acts to hedge the price of natural gas. The Wescott liquefied natural gas ("LNG") and liquefied petroleum gas ("LPG") storage facility is one of the largest peak-shaving facilities in the region. NSP also operates a LPG peak shaving facility connected to our Grand Forks distribution system. The peak shaving facilities allow the Company to meet the "needle peak" demands caused by extreme winter weather without contracting for annual or seasonal pipeline capacity. These assets and supply resources also positioned us well to respond to the expiration of our current contract with Northern Natural Gas, which provides upstream transportation service into Viking for delivery to our North Dakota distribution systems. Our aggressive pursuit of a diverse supply portfolio led to our ability to make new arrangements that will provide significant benefits to our customers.

Q. WHAT OTHER ACTIONS HAS THE COMPANY TAKEN ON SUPPLY RELATED ISSUES?

A. Public policy plays an important role in energy production. We have worked hard for the past several years to support a national energy bill that will expand domestic sources of natural gas supply.

Q. DID THE COMPANY MAKE OTHER CHANGES IN RESPONSE TO THE SIGNIFICANT WHOLESALE COMMODITY PRICE VOLATILITY?

A. Yes. The Company has changed its purchasing practices to mitigate the extreme variability in wholesale gas supply prices that have become much more common. Years ago, the Company purchased supplies under contracts

linked to monthly index prices and did not hedge any of its supply portfolio, as the cost of taking some of the variability out of the wholesale commodity market was not offset by the benefits. With wholesale commodity prices reaching in excess of $12/Dkt in January 2001 and $11/Dkt in March 2003, and significant month to month variations, the value of hedging a portion of our supply portfolio for customers has increased dramatically. Today we hedge up to 50% of our supply through the use of storage gas (providing a seasonal price hedge) and financial instruments. The Company has responded to the gas price volatility in managing its business in a way that continues to offer customers the benefits of its supply acquisition plans.

Although the potential of expanded LNG and construction of the Alaskan Pipeline may potentially mitigate long-term wholesale prices, the current high price environment and its associated volatility are expected to continue over the near term.

Q. HAVE THESE ACTIONS BEEN SUFFICIENT TO AVOID THE IMPACTS OF A VOLATILE WHOLESALE COMMODITY MARKET?

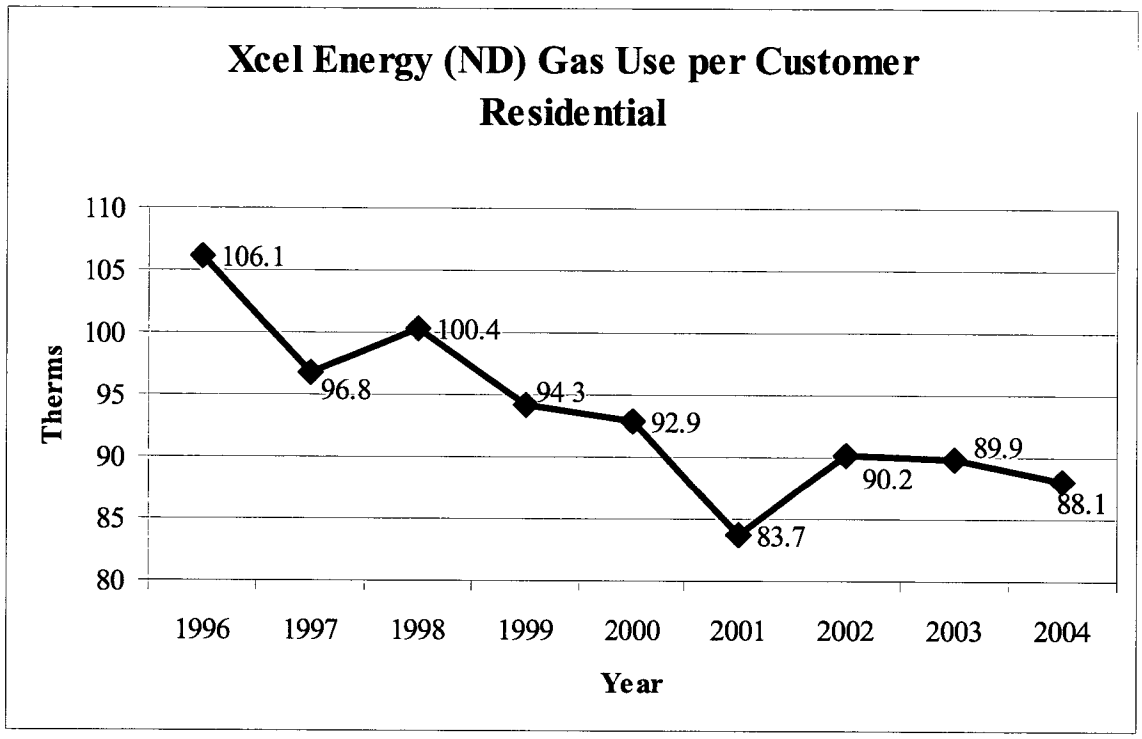
A. No. While we work hard to manage our portfolio as efficiently as possible, there is little we can do to prevent the effects of the current wholesale natural gas market from reaching our customers. That is why we are making proposals to modify our retail distribution rate structure to further manage volatility as it affects our customers and the Company.

Q. WHAT ARE THE FACTORS THAT CONTRIBUTE TO VOLATILITY IN CUSTOMER BILLS?

A. There are two main factors that contribute to volatility from the customer's perspective: wholesale gas supply prices and weather. The change in wholesale natural gas supply pricing over the past six years has been substantial, with commodity prices changing from an average of $2.00/Mcf in 1998 to $5.25/Mcf in 2003, with significant month to month variations. These wholesale costs are directly recoverable from customers through the Cost of Gas ("COG") rider in our tariffs.

Table KTL-1 shows that customers have responded to these prices by reducing usage dramatically. In one of the largest efficiency gains in the North Dakota energy sector, residential use per customer (for customers with space heating) has declined from a high of 106 therms/year in 1996 to 88 therms/year projected for 2004. Even with this significant decrease in usage, average residential bills in North Dakota increased by over 31 percent, from $593 in 1996 per year to $779 per year in 2003 because of higher wholesale commodity supply costs.

TABLE KTL-1



Q. YOU ALSO MENTIONED WEATHER AS A CAUSE OF VOLATILITY. PLEASE EXPLAIN HOW WEATHER IMPACTS CUSTOMERS.

A. Because the Company recovers wholesale gas costs (and presently, a significant portion of gas distribution costs) on a volumetric (per therm) basis, colder than normal weather leads to higher volumes and thus higher bills, while warm weather leads to lower volumes and relatively lower bills. None of us can control the weather; thus it is difficult for customers to know with certainty what their bills will be over a coming winter period.

Wholesale gas costs and weather are interrelated. Colder weather and high demand tend to drive up wholesale gas supply prices, leading to a compounded effect on customers' bills. For example, in January 2004 wholesale commodity gas prices averaged $8.70/Dkt. Given the colder-than-

normal weather that month, the average residential bill for that month was up 18.5% from the previous winter when gas prices averaged $7.48/Dkt but weather was warmer than usual.

Q. WHAT ACTIONS HAS THE COMPANY TAKEN IN LIGHT OF THIS SITUATION?

A. For years, the Company has engaged in mitigation efforts, using tools such as:

- Budget Helper to encourage customers to levelize their bill payments over the course of a year;
- Financial instruments and storage to help manage volatility in wholesale gas supply prices.

Nonetheless, even with these efforts, customer bills can vary significantly from year to year, and have become increasingly volatile over the past several years.

Q. ARE THERE ANY OTHER ISSUES THAT CONTRIBUTE TO VOLATILITY FROM THE CUSTOMER'S PERSPECTIVE?

A. Yes. Bill volatility can be further compounded due to the fact that the Company currently recovers the vast majority -- approximately 80 percent -- of its non-gas distribution costs through volumetric (per therm) Distribution charge, even though most of the costs of providing distribution services are fixed. (By comparison, as I understand, interstate gas pipelines recover 100 percent of their fixed costs through fixed charges.) Thus, in high demand years, customers actually overpay for the costs of providing distribution service, all other things being equal, simply because the quantity of gas consumed is higher than normal. In warmer-than-normal years, the opposite holds true. This variability further contributes to the volatility in customers' gas bills over time.

Q. PLEASE DISCUSS THE ISSUE OF VOLATILITY FROM THE COMPANY'S PERSPECTIVE.

A. The same factors that cause volatility for our customers directly impact the Company – that is, weather and usage patterns contribute to volatility in our earnings from the natural gas business. Changes in wholesale gas supply pricing do not directly impact Company earnings because wholesale gas costs are recovered dollar for dollar through the COG mechanism. However, such price changes influence customer consumption patterns through declining use per customer; thus, they pose indirect but very real impacts for the Company.

Weather impacts the Company in a manner similar to, but inverse from, how it affects the customer. Although we can neither predict nor control its year-to-year impacts, weather can substantially influence Company earnings. Cold, high-volume years will generate more earnings for the Company than mild, moderate-volume years.

In North Dakota, the Company's gas distribution rates are established based on a sales forecast that assumes "normal" weather and thus a "normal" number of heating degree days. However, winter weather has been warming over time. During the six year period 1998 through 2003, the North Dakota service territory experienced 5 warmer than normal years and only 1 year when temperatures were colder than normal. Our system in North Dakota and Minnesota has also experienced an average annual reduction of 19 heating degree-days over the past 25 years. We believe our rate structure must respond to this change.

In addition to the effects of weather on our sales volumes, however, are customer consumption patterns. The average use per customer – particularly in the residential class, which constitutes 85% of Xcel Energy's natural gas customer base in North Dakota and 31% of our overall natural gas sales in the state – has been steadily declining over time. This trend stems primarily from:

- Improvements in appliance and equipment efficiencies due to new government mandates and new technologies;
- Changes in building codes that significantly lower energy use per square foot of space;
- New housing patterns, such as the significant trend to townhomes and multi-family housing, that result in lower consumption per residential unit and thus provide significantly less gas distribution revenue for a similar investment by the Company in gas distribution service equipment.

Q. WHAT IS THE IMPACT OF THIS DECLINING USE TREND ON THE GAS DISTRIBUTION BUSINESS?

A. The declining use trend makes it difficult to establish rates that will reasonably allow a utility the opportunity to earn its authorized rate of return going forward using the Company's current rate structure. Because so much of Xcel Energy's fixed costs are recovered through volumetric charges, and these energy charges are linked to a declining usage pattern, the gas utility business is not able to continue to recover its rising costs and earn an adequate return.

The Company believes this impact of declining use will grow over time. As we move into what appears to be a period of prolonged higher wholesale

commodity prices and corresponding declining retail use, it will likely become more difficult to manage the business to earn a reasonable return.

Q. HOW SIGNIFICANT IS THE IMPACT OF DECLINING USAGE PROJECTED TO BE?

A. We sought to model the potential impact of projected declining use per customer on rates of return over time. In doing so, we reflected normal levels of cost increases that could reasonably be expected to occur outside of the test year (in non-gas costs), as offset by projected growth in the number of gas customers. We then calculated anticipated annual earnings erosion that results if the historical trend in annual decline in use of 2.2% were to continue. Exhibit___(KTL-1), Schedule 4 contains the returns anticipated by that analysis. As can be seen from the data, decline in use per customer causes earnings to decline as sales do not generate sufficient distribution revenues to help keep pace with anticipated growth in annual revenue requirements.

Q. CAN XCEL ENERGY ADDRESS THIS SITUATION THROUGH PRUDENT MANAGEMENT OF GAS DISTRIBUTION COSTS?

A. No, not fully. Total non-gas operating and maintenance expenses have actually decreased from levels reported in 2001, the year our last base rate increase went into effect. We have aggressively controlled these costs yet continue to earn inadequate returns because of rising investment-related costs, declining consumption and our current rate structure.

Q. WHAT ASSUMPTIONS UNDERLY THE COMPANY'S EXPECTATION REGARDING FUTURE COSTS?

A. The expected cost increases represented on Exhibit___(KTL-1), Schedule 4 stem from estimates of rate base additions needed to support the business and

respond to community or governmental requirements for facilities relocations or new investments, continuing increases in depreciation, and general inflationary trends. I project that we cannot reasonably offset the effect of the declining use-per-customer trend through cost management.

Q. HOW DOES CUSTOMER GROWTH IMPACT INCREASING COSTS?

A. Using growth to offset and manage overall cost increases is a typical business strategy and is expected of utilities between rate cases. It is becoming more apparent, however, that growth in the number of gas customers is not sufficient to offset *both* cost increases and declining average use per customer.

In recent years we have focused our growth strategy primarily on "in-fill" opportunities rather than new expansion. "In-fill" efforts attempt to add customers on already-existing main lines in an effort to improve the cost-effectiveness and recovery of an existing investment. It thus seeks to increase sales without requiring major expansion of facilities. While this strategy has been successful for us (we have added approximately 1,100 customers per year in North Dakota since 1998), we believe this trend may also be on a slight decline. Even our historical growth has only allowed us to partially offset and moderate the increasing-cost/usage trend.

Another significant impact on the North Dakota gas distribution business has been the effect of wholesale commodity prices on our interruptible classes. The Company was able to recover increases in costs in the 1980s and early 1990s, in part, because much of the interruptible load we lost during the gas supply crisis of the late 1970s returned to gas use when wholesale commodity prices fell. In addition, those energy intensive businesses -- like J.R. Simplot --

grew with the strong growth in the economy. Now that wholesale gas prices have increased so substantially, further levels of industrial uses are uncertain. In addition, because of the proximity of the Viking system to many of our largest customers, the Company cannot substantially increase non-gas Distribution rates to the industrial classes because these customers could simply bypass the Company's system and connect directly to Viking.

Q. DO YOU EXPECT THAT THIS TREND OF DECLINING USE WILL CONTINUE?

A. Yes. Although periods of extreme volatility lead to greater uncertainty in predicting the rate of decline, the Company believes the trend will continue. The changes in federal appliance standards indicate that when households encounter the need to replace aging equipment, the new equipment will be more energy efficient. We can expect to see this impact over the lifecycle of various appliances, which can have useful lives of roughly 20 years, which correlates to a full replacement of furnaces up to new efficiency standards through the end of this decade.

Furthermore, the significant changes in gas supply prices give customers further incentives to implement actions to conserve (like adding insulation). Assuming natural gas consumption is elastic, customers' bills over the last several years should lead to increased actions to reduce usage, rather than a halt to that trend. While I cannot predict whether or when this trend will level off, I see no indication of it doing so over the next few years, a period in which wholesale gas prices are forecasted to remain high.

Trends in usage and customer additions both indicate that our effort to match costs and revenue in the test year will not represent the Company's future cost

and revenues. As a result, it is necessary to implement additional initiatives to address this situation if the Company is to have an opportunity to recover its cost of providing service.

Mr. Paluck, our rate-design witness, offers detailed proposals to help mitigate volatility for both customers and the Company.

Q. PLEASE SUMMARIZE THE RATE DESIGN PROPOSALS THE COMPANY IS MAKING IN THIS PROCEEDING TO ADDRESS THE VOLATILITY ISSUE.

A. We are sponsoring the following interrelated proposals to help both our customers and the Company manage volatility:

- *Increasing fixed charges to better match costs.* Utilities and regulators have long debated the appropriate level of customer and other fixed charges. While it is undisputed that the Company's current residential Basic Service charges are priced far below the cost of providing service, the debate has historically focused on non-cost considerations, such as customer acceptance and moderation of bill impacts. In today's environment, we believe more appropriately priced Basic Service charges are necessary as they further mitigate or remove intra-class subsidies and reduce the weather-related volatility of overall customer bills. Customers already face higher bills in cold years, given higher usage and higher wholesale gas prices. The level of these bills should not be further increased due to the recovery of fixed costs through the volumetric Distribution charge. Likewise, Company earnings should not swing as significantly as they currently do because of weather or changes in customer usage patterns. Recovering a greater portion of fixed costs through higher Basic Service charges

would help the Company address earnings volatility.

Mr. Paluck presents two options related to increasing the residential Basic Service charge. The first is a moderate increase from the current $5.50 per month to $8.50 combined with the below-described partial decoupling proposal. The other option is a residential customer charge of $14 per month without any decoupling mechanism.

- *Implementing a "partial decoupling" mechanism.* "Decoupling" is a term used to describe efforts to separate recovery of costs from sales volumes. A number of states have implemented decoupling mechanisms in a variety of forms to offset the impacts of weather or declining use per customer, or to encourage utility support for conservation and demand-side management efforts. By removing the link between cost recovery and actual gas sales, a decoupling mechanism would mitigate the impact of the declining use per customer trend on Company earnings. The Company's proposed decoupling mechanism is similar to that recently approved for Montana-Dakota Utilities ("MDU") in Case No. PU-399-04-97, except that it does not address other factors affecting customer usage, such as weather.

Q. WHAT DO YOU RECOMMEND THE COMMISSION ADOPT?

A. As noted earlier, we recommend that the Commission approve either our proposal for more moderate increases in Residential and Commercial/Industrial Basic Service customer charges combined with a partial residential decoupling mechanism; or approve substantially higher,

cost-based Basic Service charges. We do not believe that adoption of both the higher Basic Service charge and the decoupling mechanism is needed or appropriate at this time, as both proposals attempt to address similar issues.

Q. PLEASE EXPLAIN.

A. Both approaches provide a more reasonable opportunity to attempt to earn our authorized return on equity. A partial decoupling approach (combined with a modest increase in the Basic Service charge) is directed at addressing earnings volatility from the perspective of a decline in average use per customer. The proposal would use weather-normalized sales volumes and thus not mitigate weather related earnings volatility. The proposal has the benefit not discouraging Company support of customer conservation efforts, as declining sales resulting from more efficient use would no longer financially harm the utility. Higher Basic Service charges offer the benefit of mitigating earnings volatility for both weather and declining use impacts as less margin is recovered through the Distribution charge. There is some moderate level of customer volatility mitigation as well. As I mentioned earlier, it is during the coldest months that gas prices are at their highest and leaving a high level of fixed cost recovery in the volumetric Distribution charge tends to increase bill impacts when they are already at their highest. Shifting to greater, cost-based Basic Service charges mitigates this impact.

Q. DOES THE COMPANY HAVE A PREFERENCE FOR EITHER ALTERNATIVE?

A. Yes. While both approaches address the problem, we believe that partial decoupling effectively aligns customer and Company interests while avoiding concerns regarding a high percentage rate change impact on low use

customers that would result from implementing a $14 Basic Service charge for the Residential class.

While we strongly believe that changed circumstances in the retail gas distribution business warrant a change in approach, we have offered for consideration an alternative proposal for a more cost-based increase in residential customer charges. We believe this customer charge proposal represents a pricing option commonly seen in local telephone and cable services, and it offers a reasonable alternative for the Commission to consider if it is uncomfortable with the concept of partial decoupling.

Q. WHAT ARE THE BENEFITS OF THE COMPANY'S PROPOSAL?

A. Our proposal is a solid first step in providing customers the benefit of more stable bills over time. Because of the more fixed nature of costs, customer bills would reflect more closely the costs of providing gas distribution services. Customers would also benefit from removal of any current disincentive for the Company to promote conservation.

The Company would benefit from our proposal because, by eliminating the impact of the trend of declining usage per customer, the regulatory framework would provide for a more reasonable opportunity to earn our authorized return. Even with a partial decoupling mechanism the Company will continue to have every incentive to prudently manage costs.

Q. IS THE COMPANY'S PARTIAL DECOUPLING PROPOSAL A DEPARTURE FROM CURRENT RATEMAKING PRACTICE?

A. No. The Commission recently approved a "Distribution Delivery Stabilization Mechanism," which I understand is a decoupling methodology, for Montana-Dakota Utilities ("MDU") in Case No. PU-399-04-97 in September 2004. In comparison to the MDU mechanism, our proposal would result in a smaller annual rate adjustment because it only includes the impacts of declining use. The MDU mechanism adjusts for all factors that would affect customer usage (weather, declining use, short term price elasticity).

In addition, it is a proposal that is generally consistent with activity in other jurisdictions. Attached as Exhibit___(KTL-1), Schedule 5 is the joint news release of the American Gas Association ("AGA") and the Natural Resource Defense Council ("NRDC") encouraging the use of both our primary and alternative approaches to encourage the efficient consumption of natural gas during this period of high gas prices. Other states besides North Dakota have implemented similar mechanisms to address these issues. Xcel Energy has proposed implementation of the same mechanism for its natural gas utility operation in Minnesota. I believe the current business environment warrants review and justifies the need to implement the proposed measures, while still retaining most components of the existing ratemaking framework.

Q. DO YOU HAVE ANY CONCLUDING REMARKS ABOUT THE VOLATILITY ISSUE?

A. Only that I believe changes in the marketplace have been significant enough to warrant a change from the status quo. Regulation should be responsive to those changes and, where appropriate, implement proposals that help align the interests of customers and the Company. I believe we have put forth an appropriate plan for addressing these issues, working to address both customer and Company concerns. In addition to approving the proposed

increase in revenues, I respectfully request that the Commission approve measures that address volatility in an effective manner.

VI. LOOKING FORWARD

Q. WHAT ISSUES DOES THE COMPANY ANTICIPATE FACING IN THE FUTURE?

A. I believe we will continue to experience relatively high wholesale commodity gas prices and volatility in wholesale pricing at least for the near term. These issues call for the development of additional measures to help manage costs for customers.

Q. DOES THE COMPANY HAVE ANY INITIATIVES IN MIND WITH RESPECT TO GAS COSTS?

A. Yes. We are exploring the potential use of Performance-Based Regulation ("PBR") for our local gas distribution operations, similar to the PLUS Plan that is currently in place for the Company's electric utility operations.

While we do not have proposals to advance in this case, we would like to explore this issue with the Commission and perhaps other interested parties and propose an initiative in the future.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company requires a rate increase of $1,280,000 or 1.8 percent in order to recover our prudent costs of providing natural gas service, including a reasonable rate of return on equity. While we have exercised prudent and effective management over time, we cannot offset the trends of increasing costs and declining use per customer without a rate increase. Thus, this rate increase is needed to return the gas operations to a reasonable and fair rate of return, based on a 2004 test year.

We propose to recover costs through a rate design that fairly and appropriately allocates costs to the various customer classes and helps mitigate the impacts of price and bill volatility for customers. These initiatives will benefit both customers and the Company over time through increased stability.

The changes in the industry over the past few years have been significant. This rate case offers a good opportunity to address these issues, since the overall requested rate increase is relatively small. Therefore, the Company respectfully requests that the Commission approve:

- Our requested rate increase of 1.8 percent;
- A rate of return of 9.43 percent, which includes a rate of return on equity of 11.5 percent; and
- Our proposed rate design and tariffs.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of	)	
Northern States Power Company d/b/a	)	
Xcel Energy - Notice of Change in Rates	)	Case No. PU-400-04-578
For Natural Gas Service	)	

AFFIDAVIT OF
Kent T. Larson

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

_____
Kent T. Larson

Subscribed and sworn to before me, this ____ day of _____, 2004.

_____
Notary Public

Mr. Kent T. Larson
Vice President, Jurisdictional Relations
414 Nicollet Mall, Minneapolis, MN 55401

CURRENT RESPONSIBILITIES

Leadership and management of Xcel Energy's jurisdictional relations, local government and community affairs across ten states in which the Xcel Energy operating companies provide utility services. Leadership for regulatory and legislative affairs in North Dakota and South Dakota.

PREVIOUS EMPLOYMENT

State Vice President, MN and Dakotas	Xcel Energy Services Inc.	2001-2004
State Vice President, MN		2000-2001
Chief Executive and Managing Director	Northern States Power Company	1997-2000
Director, Sales – MN		1994-1997
Manager, White Bear Lake Area		1992-1994
Manager, Operations – South Dakota		1990-1992
Engineering and Engineering Leadership		1982-1990

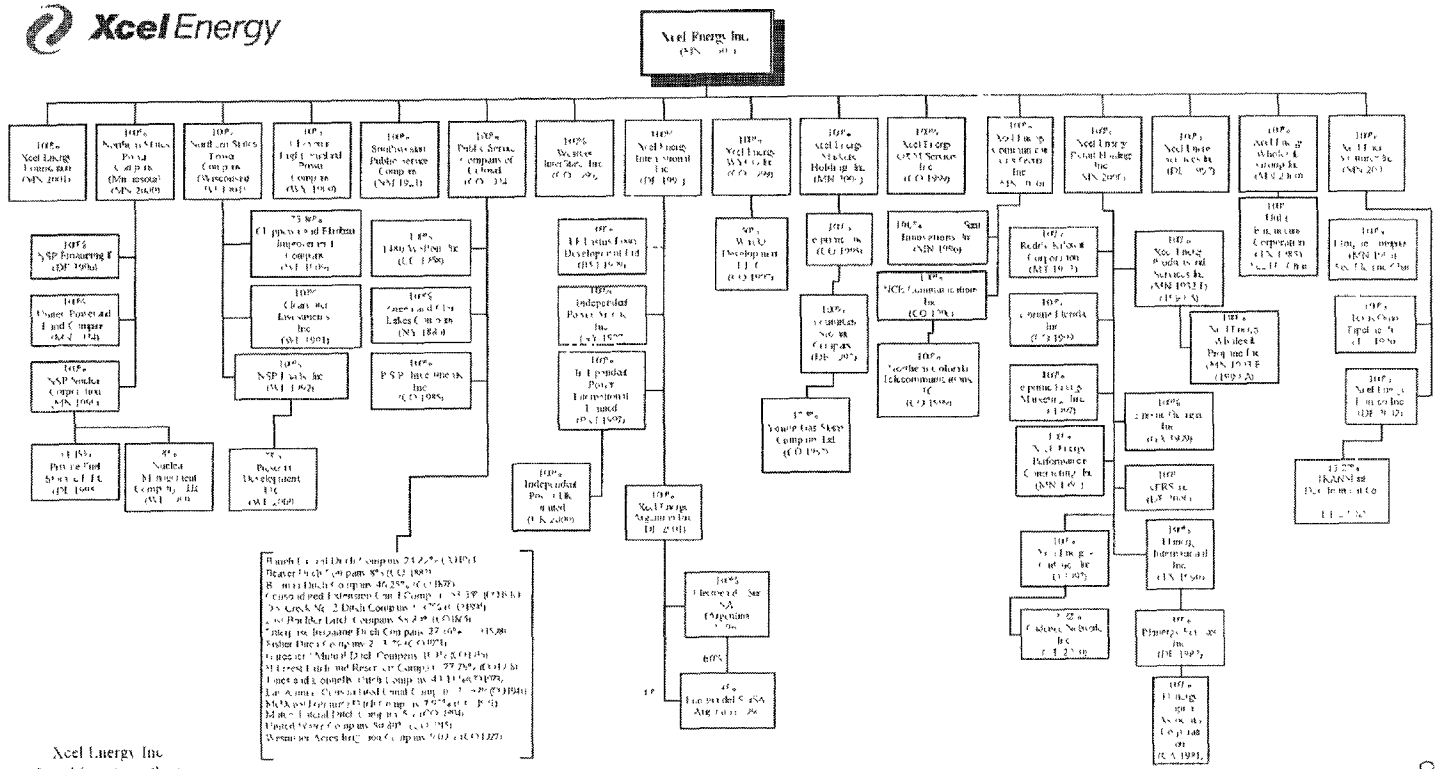
EDUCATION

- Master of Business Administration, University of St. Thomas, 1985
- Bachelor of Science, Electrical Engineering, Iowa State University 1981
- Registered Professional Engineer – Minnesota – Current

PREVIOUS TESTIMONY

North Dakota PSC	Northern States Power Company	Case No. PU-400-99-418 (merger filing)

Xcel Energy



Xcel Energy Inc
Legal Structure Chart

September 14, 2001

I = Formation Date
A = Acquired Date

To be Updated

Case No. PU-400-04-578
Exhibit ___ (KTL-1)
Schedule 2

Northern States Power Co. d/b/a Xcel Energy
Gas Utility - State of North Dakota
Change in Gas Use Per Customer (Weather Normalized)

Case No. PU-400-04-578
Exhibit ___ (KTL-1)
Schedule 3

Calendar Month Sales (therms) per Customer

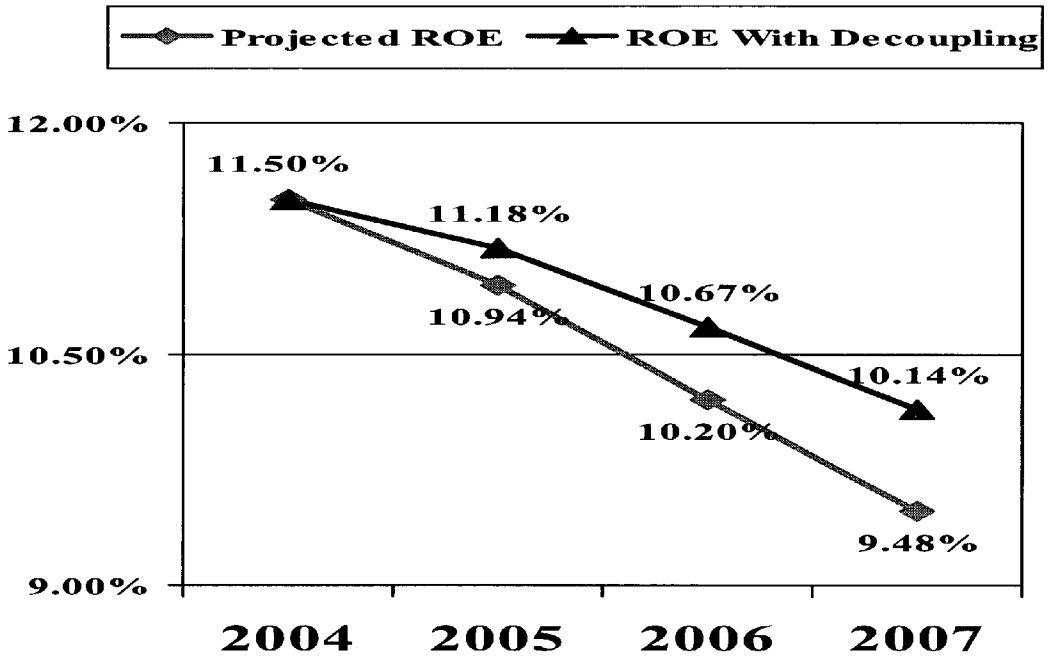
Year	Residential	Commercial	Total Firm	Interruptible	Total Retail
1996	106.1	769.8	200.3	14,426.4	252.4
1997	96.8	747.1	189.7	23,797.3	286.2
1998	100.4	733.4	190.8	17,498.9	261.6
1999	94.3	710.8	184.0	15,240.8	245.8
2000	92.9	713.0	185.6	15,786.0	237.4
2001	83.7	622.6	165.1	13,183.3	208.2
2002	90.2	675.7	179.8	12,625.9	221.3
2003	89.9	597.6	166.9	14,086.4	212.5

Annual % Change

Year	Residential	Commercial	Total Firm	Interruptible	Total Retail
1997	-8.8%	-2.9%	-5.3%	65.0%	13.4%
1998	3.7%	-1.8%	0.6%	-26.5%	-8.6%
1999	-6.1%	-3.1%	-3.6%	-12.9%	-6.0%
2000	-1.4%	0.3%	0.9%	3.6%	-3.4%
2001	-9.9%	-12.7%	-11.1%	-16.5%	-12.3%
2002	7.7%	8.5%	8.9%	-4.2%	6.3%
2003	-0.4%	-11.6%	-7.2%	11.6%	-4.0%
Average 97-03	-2.2%	-3.3%	-2.4%	2.9%	-2.1%

Illustrative Impact On Return On Equity Of Partial Decoupling Proposal

Case No. PU-400-04-578
Exhibit____(KTL-1)
Schedule 4



Based On: Rate Base Up 5.0%/Yr, Customer Growth 1,100 Customers/Yr,
O&M Up 2.0%/Yr, Use Per Customer Down 2.2%/Yr



American Gas Association



Joint Statement of the American Gas Association and the Natural Resources Defense Council

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not profit from their acquisitions of natural gas to serve customer needs. The profit

(authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the expectation that weather will be normal, on average, and that customer use of gas

[1]For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. *See* Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management. Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

Direct Testimony and Schedules
Jeffrey C. Robinson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company
d/b/a Xcel Energy
Notice of Change in Rates
For Natural Gas Service

Docket No. PU-400-04-578
Exhibit___

Overall Revenue Requirements
Rate Base
Income Statement

December 1, 2004

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey C. Robinson. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Manager of Revenue Analysis for Xcel Energy Services Inc. ("XES" or "Service Company"). My resume is included as Exhibit___(JCR-1), Schedule 1.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over thirty years of employment experience with Northern States Power Company, the predecessor company to Xcel Energy Inc., and with XES. I have an extensive background in matters that concern the capital invested in utility property. I have held management positions in the areas of Depreciation Services, Depreciation & Nuclear Fuel Accounting, Corporate Economics & Depreciation, and Capital Asset Accounting. I have been in my present Revenue Analysis management position since 1994. I am responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for electric and gas utility operations filed with the North Dakota Public Service Commission ("NDPSC" or "the Commission"), the Minnesota Public Utilities Commission ("MPUC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC").

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company d/b/a Xcel Energy ("NSP", "Xcel Energy" or "the Company"), the utility operating company subsidiary of Xcel Energy Inc. providing natural gas and electric service in North Dakota.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will provide testimony supporting the Company's financial data and its Notice of Change in Rates for Natural Gas Service ("Notice") for the State of North Dakota retail natural gas jurisdiction. My testimony addresses the North Dakota jurisdiction's retail gas operations' overall retail revenue requirement of $70,121,000 and revenue deficiency of $1,280,000, determined by the cost of service for the 2004 budget test year.

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes they were.

II. DATA PROVIDED AND SELECTION OF TEST YEAR

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Financial data is provided for the most recent fiscal year, that being calendar year 2003, and the test year selected, calendar year 2004.

Financial data for the most recent fiscal year and the test year are adjusted for traditional regulatory adjustments (e.g. charitable donations, organizational dues, etc.). The test year on which the Notice is based starts with financial data included in the Company's 2004 projected fiscal year budget, and then includes ratemaking adjustments deemed necessary along with refinements and corrections to 2004 budgeted data made to assure the appropriateness for purposes of developing a test year that provides a normalized level of rate base and expenses to establish just and reasonable rates. Separate rate base and income statement bridge schedules that identify test period adjustments are provided with my testimony and will be identified as the test period adjustments. These adjustments are discussed later in my testimony.

Q. HOW DID THE COMPANY SELECT THE PROPOSED TEST YEAR FOR THIS PROCEEDING?

A. Calendar year 2004 was selected as the test year for this filing using Xcel Energy's first-year budget data. The test year is based on the most recent available budget information that is deemed appropriate for ratemaking purposes.

Q. DOES THE 2004 PROJECTED TEST YEAR MEET THE COMMISSION'S REQUIREMENTS?

A. Yes. This is consistent with the intent of North Dakota Century Code ("NDCC") § 49-04-04.1, subd. 2:

(a) The test year budget data is reasonable, reliable, and made in good faith and all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the commission to test the appropriateness of the forecast; and

(b) the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment to be applied in recording the events once they have occurred.

In my opinion, the 2004 Company budget data, as adjusted for the known and measurable changes discussed below, is a reasonable representation of the costs and rate case expense the Company will incur to provide natural gas service in the State of North Dakota, and complies with NDCC § 49-05-04.1, subd. 1(b). Thus, the budget 2004 test year data is reasonable and appropriate for setting rates in this proceeding.

Q. NDCC § 49-05-04.1, Subd. 1(b) REQUIRES A UTILITY TO FILE "HISTORIC PERIOD" DATA. HOW IS NSP COMPLYING WITH THIS REQUIREMENT?

A. Schedules 11 and 12 to my testimony are excerpts from the Company's reported 2003 actual jurisdictional data provided in our May 1, 2004 jurisdictional annual report to the Commission.

III. TEST YEAR BUDGET DEVELOPMENT

Q. DESCRIBE THE TEST YEAR BUDGET PROCESS.

A. The budgeting process for the 2004 test year began in late August 2003 with the issuing of Budget Guidelines and Instructions to the various business areas about the 2004 budget preparation. The test year budget is assembled separately by its various components: Sales Forecast (customers and consumption), Retail and Other Revenues, Cost of Gas Supplied, Operating and Maintenance ("O&M") Expenses, Capital Invested, Other Rate Base

Investment and Capital Structure Components. The various budgets are submitted to the senior management of Xcel Energy Inc. ("XEI"), known as the Governance Council, for review. All final O&M, labor and capital expenditure budgets are submitted to the Company and XEI Board of Directors for approval. Management uses the final budget, as approved, to monitor and manage the Company's operations and financial performance during 2004.

Q. DESCRIBE HOW COSTS FOR THE NORTH DAKOTA JURISDICTIONAL GAS OPERATIONS ARE DEVELOPED IN THE BUDGET PROCESS.

A. As discussed by Mr. Larson, one significant change from prior Company rate cases is that the Company is now part of a registered holding company system, with XES providing corporate services to the entire XEI family of companies. Previously, for example, corporate costs incurred at Old NSP (parent company level) were allocated to subsidiaries of Old NSP. Now, many of those costs are budgeted and incurred at the Service Company and allocated to the utility and other subsidiaries, including NSP.

However, the change in structure does not change the basic methodology for allocation of budgeted costs. Costs from the Service Company are typically either directly assigned or allocated to the Company and then assigned or allocated to the appropriate business unit. Each business unit is responsible for appropriate FERC designation of its budgeted O&M dollars. The JDE (our accounting system) business unit and object account determine the FERC account. Each JDE business unit description is required to give enough information to determine the appropriate FERC account classification. In addition, the business units are responsible for including a location code where appropriate. This information helps facilitate appropriate legal entity (e.g.,

NSP), utility (e.g., natural gas or electric utility) and jurisdictional (e.g., North Dakota or Minnesota) cost assignment.

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2004 BUDGET FOR CERTAIN TRADITIONAL REGULATORY ADJUSTMENTS. PLEASE DESCRIBE THE ADJUSTMENTS.

A. I made the following adjustments to the 2004 Budget to comply with the traditional regulatory adjustments made by the Commission. Those adjustments are:

1) Charitable Contributions
2) Advertising Expenses
3) Organizational Dues
4) Tax Benefit Transfer Leases
5) Interest on Customer Deposits

Q. DID YOUR ANALYSIS OF THE O&M, LABOR AND CAPITAL BUDGETS REQUIRE THAT ADDITIONAL ADJUSTMENTS BE MADE TO OBTAIN A TEST YEAR BUDGET FOR RATE CASE PRESENTATION?

A. Yes. As part of the preparation of any rate case, an additional level of internal review of budget data is undertaken. The underlying financial operation and capital data was scrutinized for anomalies and errors. During the process of evaluating the budget data, a few coding errors, inconsistencies and misclassifications were discovered and appropriate adjustments were made and included in the Test Year.

Q. PLEASE LIST THE TYPES OF ADJUSTMENTS MADE BECAUSE OF THE DATA REVIEW PROCEDURE.

A. The adjustments made to the initial budget data included:

1) Remove certain costs related to federal government affairs.

2) Remove legal costs originally charged to common and allocated in part to natural gas utility operations that should have been directly charged to electric utility operations and/or the XEI holding company.

3) Remove costs related to new financial modeling software that was miscoded and assigned to the NSP gas utility and should have first been assigned to Common and then allocated in part to the gas utility.

4) Adjust for an assignment of costs between electric and gas operations for locating facilities.

5) Adjust for an assignment of costs between electric and gas operations for meter shop labor.

6) Remove certain costs identified as gas system reliability expenditures determined to be direct costs of electric projects.

7) Remove a miscoding of assignment of non-gratuitous credits (work performed on customer premises to be reimbursed).

8) Adjust for a miscoding of costs for new gas distribution system control software that will be classified on the books of both Public Service Company of Colorado and NSP but was inadvertently classified to NSP.

9) Adjust rate base to include hedging (e.g., financial instrument) balances.

Q. DO YOU HAVE A SCHEDULE THAT IDENTIFIES THE TRADITIONAL REGULATORY ADJUSTMENTS AND THE ADJUSTMENTS THAT RESULTED FROM THE REVIEW OF THE PROJECTED YEAR BUDGETED DATA?

A. Yes. Exhibit___(JCR-1), Schedule 2 provides a list of the adjustments and the associated amounts to the 2004 budget.

Q. ONCE YOU COMPLETED THESE INITIAL ADJUSTMENTS TO THE BUDGET BASE DATA, DID YOU FURTHER ADJUST THE BASE DATA TO DEVELOP THE TEST YEAR?

A. Yes, I made a number of test period adjustments that affected either the rate base or the income statement. A list of these test period adjustments is shown on Exhibit___(JCR-1), Schedule 3. I will also discuss the nature of each adjustment later in my testimony.

Q. IS THE COMPANY'S BUDGETING PROCESS CONSISTENT WITH PREVIOUS BUSINESS PRACTICES?

A. Yes. In order to provide a clear look at the changes in the cost of service for the North Dakota gas utility operations, the budget documentation includes a functional comparison of 2003 actual to the 2004 budget fiscal year and an explanation of significant deviations. The budget documentation also includes a 2003 actual to 2004 budget comparison by FERC account. Besides budget documentation, department budget workpapers exist to further support the budget preparation process.

Q. ARE THERE SOME DIFFERENCES IN THIS BUDGET PROCESS COMPARED TO THE ONE PRESENTED IN THE TEST YEAR FOR THE COMPANY'S 2000 GAS RATE CASE?

A. Yes. There are two major differences that are a result of our changing corporate structure. First, as discussed earlier, most Administrative & General expenses are assigned and allocated to NSP from the Service Company pursuant to allocation processes regulated by the Securities and Exchange Commission ("SEC"). Second, the natural gas business at NSP is no longer its own business unit with its own distinct budget. Rather, most of the

operational portions of the gas utility business are integrated with electric utility functions within the Customer & Field Operations Business Unit.

IV. TEST YEAR REVENUE DEFICIENCY

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR NORTH DAKOTA?

A. The jurisdictional retail revenue requirement for North Dakota gas utility operations is $70,121,000 based on average rate base and projected net operating income for the 2004 test year, the average capital structure, short-term debt, long-term debt and 11.5 percent cost of equity capital indicated by Mr. Larson, which is in the range recommended by Dr. McDermott.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE TEST YEAR?

A. The amount of the revenue deficiency for the test year is $1,280,000. A summary of the revenue deficiency is shown in Exhibit___(JCR-1), Schedule 4 as a comparison of the jurisdictional revenue requirement amount for the test year with the forecasted revenues for the same period under present rates approved by the Commission in Case No. PU-400-00-521. The level of North Dakota retail gas rates must be increased by this amount in order to earn an overall return on rate base of 9.43%, as calculated by Dr. McDermott.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CAPITAL STRUCTURE AND WHAT ARE THE VARIOUS COMPONENTS?

A. The capital structure employed in this case represents the Company's 2004 budgeted amounts. The costs and ratios associated with this capital structure are as follows:

	Rate	Ratio	Weighted Cost
Long Term Debt	7.33%	48.65%	3.57%
Short Term Debt	7.74%	1.11%	0.08%
Common Equity	11.50%	50.24%	5.78%
Weighted Cost			9.43%

Q. WHAT IS THE PERCENTAGE INCREASE IN REVENUES PROPOSED IN THIS CASE?

A. The revenue deficiency amount represents a 1.86% overall increase in retail revenues compared to projected retail revenues at present rates.

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR?

A. Yes, under my direction, a cost of service study was prepared. Exhibit___(JCR-1), Schedule 5 is a copy of the jurisdictional cost of service study.

Q. WHAT ARE THE MAJOR CAUSES OF THE COMPANY'S NEED FOR RATE RELIEF?

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(JCR-1), Schedule 6. The major cost element driving the revenue deficiency is related to the growth in rate base and the capital recovery requirements associated with the additional rate base investments made since the Company's last general rate increase. Changes in

operating and maintenance costs, and administrative and general costs were very minor, about 0.16 percent per year.

Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

A. The elements of capital recovery are depreciation, which is the ratable return of investment over its estimated service life, return on investment and related income taxes. Depreciation expense has increased by $581,000 since the Company's last gas rate case. This expense is driven by the increase in utility plant investment, including information systems investment allocated to the NSP gas utility business. Since the last gas rate proceeding, utility plant in-service investment in North Dakota has increased by over $12.5 million. Later in my testimony I will discuss the specifics related to changes in the average rate base investment since the 2000 natural gas rate case test year.

Q. ARE THERE OTHER COST ELEMENTS RELATED TO THE AMOUNT OF UTILITY PLANT IN-SERVICE INVESTMENT?

A. Yes. Real estate and personal property taxes are directly related to utility plant in-service investment. Increases in real estate and personal property taxes result from additional investment in plant and facilities and from higher assessment levels by taxing authorities. Fortunately, since the last rate case, the assessment rates imposed by the taxing authorities have decreased enough to almost offset the increased taxes due to growth in plant investment. As a result, the revenue requirement for real estate and property taxes has only increased by $26,000 since the last gas rate case test year.

Q. PLEASE DISCUSS THE COMPONENTS OF THE CALCULATION OF "NET SALES GROWTH" SHOWN ON EXHIBIT___(JCR-1), SCHEDULE 6, PAGE 1, LINE 10.

A. Simply defined, the line item shows the change in the gross operating income from the 2000 test period to the 2004 test period. A considerable number of gas customers have been added since 2000; however, as discussed by Mr. Larson, the underlying use per customer has decreased. The net result is a slight increase in gross operating income that provides some offset to the effects of increasing costs of operations.

Gross operating income is calculated by subtracting from total revenue the cost of gas, city franchise fees and the Grand Forks Manufactured Gas Plant ("MGP") clean-up cost amortization included in the Cost of Gas adjustment.

Q. PLEASE DISCUSS THE COST ELEMENTS OF THE REVENUE DEFICIENCY RELATED TO OPERATING EXPENSES.

A. Exhibit___(JCR-1), Schedule 6, Page 2 of 2, shows a summary of the change in operating expenses by functional class over the four-year span between the 2000 rate case test period in Case No. PU-400-00-521, and the 2004 test period in this case. The schedule also shows a calculation of the average annual percent of increase over the same period.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2004 TEST YEAR BUDGET AND THOSE IN CASE NO. PU-400-00-521?

A. Yes. Budget accounts for both periods conform to the FERC Uniform System of Accounts.

Q. DO YOU INCLUDE COMPARISONS OF THE CHANGE IN THE PURCHASED COST OF GAS AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of purchased gas is considered to be an operating expense, recovery occurs through the cost of gas adjustment ("COG") mechanism and true-up process provided in the Company's tariffs. In my analysis of the cost elements of the overall revenue deficiency, I use the cost of gas in the calculation of the Net Sales Growth Offset.

Q. WHAT IS THE AMOUNT OF CHANGE IN O&M COSTS SINCE THE LAST RATE CASE?

A. Excluding the cost of gas supply, operating and maintenance expenses have increased in total by only $31,000 since the 2000 test year. This represents an average annual increase in gas operations costs of approximately 0.16 percent, well below the level of inflation as measured by the Consumer Price Index.

V. JURISDICTIONAL COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE TEST YEAR.

A. The complete jurisdictional cost of service is included in my testimony at Exhibit___(JCR-1), Schedule 5. The jurisdictional cost of service includes: capital structure, cost of capital, income tax rates, rate base, income statement, income tax calculations and a cash working capital computation.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The summary of the jurisdictional cost of service consists of Schedule 4 and Schedule 5. In Schedule 5, the cover page identifies the North Dakota Retail

jurisdiction target, and shows the earned return on equity in North Dakota, the revenue deficiency, the percent of increase that would result if rates were increased to earn the authorized or requested return on equity (in this case 11.5 percent). The "Rate Base Summary" for total NSP natural gas operations and the North Dakota jurisdiction is shown on Schedule 5, Page 2. On Schedule 5, Page 3 an "Income Statement Summary" for total NSP natural gas operations and the North Dakota jurisdiction is shown. The income statement shows the determination of total operating income at present authorized retail rates. The "Income Tax Summary" for total NSP natural gas operations and the North Dakota jurisdiction is shown on Schedule 5, Page 4. The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 5, Page 3. The computation of cash working capital, Schedule 5, Page 6, is carried back to the rate base on Schedule 5, Page 2. Schedule 5, Page 5 shows the "Revenue Requirement and Return Summary" for total NSP natural gas operations and the North Dakota jurisdiction. Specifically, the schedule shows the calculated earned overall rate of return on rate base, calculated earned rate of return on common stock equity capital, the revenue deficiency that needs to be recovered to enable the North Dakota jurisdiction gas operations to earn the requested return on common equity and finally, the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor calculation is included in my exhibits at Exhibit___(JCR-1), Schedule 13

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as interest synchronization. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBIT THAT IS RELATED TO THE INCOME STATEMENT.

A. Exhibit___(JCR-1), Schedule 7 relates to the income statement.

Q. PLEASE IDENTIFY THE CONTENTS OF EXHIBIT___(JCR-1), SCHEDULE 7.

A. Exhibit___ (JCR-1) Schedule 7, Page 1 of 2, is a comparative income statement for the 2004 test year showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the jurisdictional cost of service study and includes the revenue deficiency in the North Dakota jurisdiction gas utility operations. Schedule 7, Page 2 of 2, shows a gas utility comparative income statement for the North Dakota jurisdiction and NSP for the 2004 test year before making test period adjustments. The operating income statement after making the proposed test period adjustments is also shown on Page 2 of 2.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO NSP'S GAS UTILITY OPERATIONS.

A. The test year includes both costs incurred directly by NSP's gas utility operating business and costs directly assigned or allocated by the Service Company for corporate functions (e.g., accounting, human resources, law, etc.). The XES cost allocation and billing process is subject to SEC jurisdiction and authorization under a Utility Services Agreement between NSP and XES. O&M cost assignments and allocations were the same as used by the Company in the recent Minnesota gas rate case filed with the MPUC. Non-O&M costs include such items as book depreciation expense, deferred income taxes and property taxes. All of the common investments and their related costs, be it software or other common investments and expenses, are evaluated as to whether the cost should be direct assigned to Electric or Gas, or allocated based on appropriate allocators such as: Customers, Customer Bills, Transportation Studies, or the Three Factor allocator used to allocate O&M expenses to utility.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE NSP GAS UTILITY OPERATIONS IN THE NORTH DAKOTA JURISDICTION.

A. O&M cost assignments and allocations are summarized on Exhibit___(JCR-1) Schedule 9.

The expense budgets relied upon to develop test year income statement items were generally prepared on a functional basis (i.e., Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales,

Administrative and General). These functional amounts are directly assigned to North Dakota jurisdiction gas operations or allocated to the gas operations based on cost causation.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING NSP'S INVESTMENT IN GAS PLANT TO THE NORTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate expenses and capital items to the North Dakota jurisdictional gas operations income statement and rate base is contained in Exhibit___(JCR-1) Schedule 10. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (i.e. Production, Storage, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing gas service in a particular jurisdiction and the underlying elements of cost causation.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENT IN PRODUCTION, STORAGE AND TRANSMISSION FACILITIES.

A. The Company's production (e.g., liquefied natural gas or liquefied propane gas), storage and transmission system is designed, built, and operated to provide an integrated source of natural gas shared by the Company's gas customers in Minnesota and North Dakota. To determine the level of investment associated with the provision of gas service to North Dakota retail customers, it is necessary to assign or allocate a portion of the total production, storage, and transmission investment to each jurisdiction.

Q. HOW WERE THE NSP GAS PRODUCTION, STORAGE AND TRANSMISSION SYSTEM INVESTMENT AMOUNTS ALLOCATED TO THE NORTH DAKOTA JURISDICTION IN THIS CASE?

A. The North Dakota jurisdiction's share of the projected system design day peak demands for the test year was used to allocate the capital investment costs. It is reasonable to use design day demand as an allocator because these facilities are designed to meet peak firm customer requirements. This is also consistent with the methodology accepted in the last two North Dakota gas rate cases, Case Nos. PU-400-00-521 and PU-400-95-559. The 2003-04 heating season design day demand factors used in this jurisdictional allocation process are consistent with the annual NSP gas supply planning process.

Q. WHAT IS THE DESIGN DAY?

A. The design day is the coldest average 24-hour period recorded for the NSP gas service area. NSP designs its gas distribution systems and contracts for natural gas supplies, transportation, storage and peak shaving to meet the supply needs of firm customers under design day conditions. The design day allocation method assigns costs to the customer population on a basis of gas service needs that cause the need for these facilities and supplies.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE NORTH DAKOTA JURISDICTION?

A. The Company's natural gas distribution plant investment amounts have been directly assigned based upon the jurisdiction(s) served by each of the individual distribution facilities.

Q. IS THE 2004 TEST YEAR RATE BASE FOR THE NSP – NORTH DAKOTA JURISDICTION GAS OPERATIONS REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The test year rate base was developed on sound ratemaking principles in a manner similar to prior Company gas rate cases.

Q. ARE THERE ANY AREAS WHERE NSP CHANGED ITS JURISDICTIONAL ALLOCATION METHOD?

A. Yes, with respect to assignment of common Administrative and General ("A&G") costs to jurisdiction. The new allocation factor that was used to assign common A&G costs, generally incurred at the Service Company, to the appropriate jurisdiction is based on customers. This change in method replaces the former method that assigned common A&G costs to jurisdiction based on an allocation factor calculated from the ultimate allocation and assignment to jurisdiction of all non-A&G labor.

VII. RATE BASE COMPONENTS

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST YEAR RATE BASE.

A. The test year rate base is generally comprised of the following major items which will be described in further detail later in my testimony:

- Net Utility Plant
- Short-term Construction Work in Progress
- Accumulated Deferred Income Taxes
- Other Rate Base Items

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Exhibit___(JCR-1), Schedule 8, Page 1 of 2, shows a detailed statement of the Average Rate Base by component for the 2004 Test Year. Schedule 8, Page 2 of 2, is a comparative statement of the 2004 Test Year Average Rate Base for the North Dakota jurisdiction and NSP, before and after making proposed test period adjustments. Exhibit___(JCR-1), Schedule 12, is an excerpt from the Company's reported 2003 actual Average Rate Base provided in the May 1, 2004 jurisdictional annual report to the Commission.

VIII. NET UTILITY PLANT

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents NSP's investment in plant and equipment that is used and useful in providing retail natural gas service to its customers, net of accumulated depreciation and amortization.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the test year. Such treatment is consistent with the method employed in the most recent North Dakota gas rate case, Case No. PU-400-00-521.

Q. WHAT HISTORICAL BASE DID NSP RELY ON AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE TEST YEAR?

A. The historical base used was NSP's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of December 31, 2003.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE TEST YEAR?

A. The ending net plant balances were determined by applying the data contained in the 2004 capital budget to the above-described beginning test year balances adjusted for retirements, depreciation, salvage and removal costs projected to occur during the test year.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE TEST YEAR RATE BASE?

A. The average net utility plant included in the test year rate base is $42,359,000, as shown on Exhibit___(JCR-1), Schedule 5, Page 2. This is comprised of an average plant balance of $75,041,000 as detailed on Exhibit___(JCR-1), Schedule 8, Page 1, minus an average depreciation reserve of $32,682,000, also shown by component on Exhibit___(JCR-1), Schedule 8, Page 1.

IX. CONSTRUCTION WORK IN PROGRESS

Q. HAS CONSTRUCTION WORK IN PROGRESS ("CWIP") BEEN INCLUDED IN THE TEST YEAR RATE BASE?

A. Yes. The only CWIP that is included in rate base are costs related to projects of a short-duration that do not accrue Allowance for Funds Used During Construction ("AFUDC"). Thus, there is no AFUDC offset added to operating income. The rate base amount reflects a simple average of projected CWIP beginning and ending test year balances. This is consistent with the method employed in the most recent North Dakota gas rate case, Case No. PU-400-00-521 and matches the use of an average rate base.

Q. HOW WERE THE TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning test year balance for CWIP was the December 31, 2003 historical balance. The beginning test year CWIP balance was adjusted to reflect projected construction expenditures, and transfers to Plant in Service during the 2004 test year to obtain the ending test year CWIP balance. These projections were developed from the Company's 2004 capital budget.

Q. WHAT WAS THE LEVEL OF SHORT-TERM CWIP INCLUDED IN THE TEST YEAR RATE BASE?

A. As shown on Exhibit___(JCR-1), Schedule 5, Page 2, the average short-term CWIP included in rate base was $101,000.

X. ACCUMULATED DEFERRED INCOME TAXES

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for corporate use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED TEST YEAR RATE BASE?

A. As shown on Exhibit___(JCR-1), Schedule 5, Page 2, $5,943,000 was deducted. This amount reflects a simple average of the beginning and projected ending test year ADIT balances.

XI. OTHER RATE BASE

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is comprised of primarily what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed further in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, gas in storage, prepayments, and various non-plant assets and liabilities. The net cash requirements, also referred to as Cash Working Capital, is shown separately.

Q. HOW HAVE TEST YEAR MATERIALS AND SUPPLIES AND GAS IN STORAGE REQUIREMENTS BEEN CALCULATED?

A. The Materials and Supplies and Gas in Storage amounts shown on Exhibit___(JCR-1), Schedule 5, Page 2, are based on the thirteen-month average balances projected during the test year. Materials and Supplies average balance included in the test year rate base equals $188,000. The test year average rate base amount for Gas in Storage is $3,834,000.

Q. HOW HAVE THE TEST YEAR NON-PLANT ASSETS & LIABILITIES BEEN DETERMINED?

A. These balances as shown on Exhibit___(JCR-1), Schedule 5, Page 2, represent the 2004 calendar year estimate of these balances. Any book/tax timing differences associated with these items has been reflected in the determination

of current and deferred income tax provision and accumulated deferred tax balances previously discussed. This group is primarily comprised of liabilities that reduce test year rate base by $574,000.

Q. HOW HAVE THE TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS BEEN DETERMINED?

A. Items of Prepayments and Other Working Capital such as customer advances and deposits, are based on the actual thirteen-month average balances during the period ended December 31, 2003, as a proxy for the test year. The unamortized balances included in this section are based on the amortization schedules as described later in my testimony on revenue requirements. The net impact of these various items increase test year rate base by $2,982,000 as shown on Exhibit___(JCR-1), Schedule 5, Page 2.

Q. HOW HAVE THE TEST YEAR CASH WORKING CAPITAL REQUIREMENTS BEEN DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses.

Q. HAVE THE COMPONENTS OF THE TEST YEAR WORKING CAPITAL BEEN CALCULATED CONSISTENT WITH METHODS USED IN THE RECENTLY APPROVED NORTH DAKOTA GAS RATE CASE, CASE NO. PU-400-00-521?

A. Yes.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made. A positive net revenue lag means that, on average, XEI investors have provided cash working capital, and are entitled to a return thereon.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE RECENTLY APPROVED NORTH DAKOTA GAS RATE CASE, IN CASE NO. PU-400-00-521?

A. Yes. In the last rate case several of the components were updated to reflect then-current experience but many of the data components were part of the original lead/lag study conducted more than ten years ago. A new lead/lag study associated with gas operations was undertaken for the Company's recent gas rate case filing to the MPUC in September 2004. The results of the new lead/lag study were incorporated into the North Dakota jurisdiction cash working capital calculations as shown on Exhibit___(JCR-1), Schedule 5, Page 2.

Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a negative $549,000. The components of this amount are summarized in Exhibit___(JCR-1), Schedule 5, Page 6.

Q. WHAT IS INDICATED BY THE NEGATIVE CASH WORKING CAPITAL AMOUNT?

A. Negative cash working capital indicates revenues are being collected in advance of the date when the associated costs of service are paid. This means

that, on average, cash working capital is being provided by parties other than the Company's investors. In the Company's circumstance, taxing authorities comprise the largest source of cash working capital. Other sources may include customers, creditors and employees. When negative cash working capital exists, it is deducted from rate base to prevent customers from paying a return on funds the Company's investors did not provide.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR GROWTH IN THE GAS UTILITY'S DISTRIBUTION PLANT INVESTMENT?

A. First, Xcel Energy has experienced customer growth in the North Dakota communities in which it provides natural gas service. Second, a significant driver of gas distribution plant investment has been related to mandated reconstruction programs where Xcel Energy is required to rebuild and/or relocate its gas system as municipal infrastructure (streets, sewer and water systems) is upgraded. Third, Xcel Energy has extended existing facilities and provided services to customers in growth areas where natural gas service was not previously available.

Q. HAS THERE BEEN A NEED FOR SIGNIFICANT CAPITAL INVESTMENTS IN THE PRODUCTION, STORAGE AND TRANSMISSION FUNCTIONS?

A. In general, the production, storage and transmission functions have not required major capital improvements.

Q. HAS THERE BEEN ANY OPERATIONAL INVESTMENTS AFFECTING THE GAS UTILITY'S TEST YEAR RATE BASE?

A. The primary operational investments that have made an impact on the Gas Utility rate base are in the area of information technology. Since the last

general rate case, XEI has invested in a number of corporate information systems and associated equipment to support business operations. These systems relate to major corporate functions such as customer service and information, human resources, corporate data warehouses and client - server technologies. All of these investments were necessary to maintain customer satisfaction and provide utility service as the electronic data age evolves.

ADJUSTMENTS TO RATE BASE

XII. ANNUALIZATION OF NEW BILLING SYSTEM

Q. IS THE COMPANY LAUNCHING A NEW BILLING SYSTEM?

A. Yes. The Customer Resource System ("CRS") is a common billing system for the utility operating companies of the merged XEI entity. The new system and the additional enhancements are expected to provide three primary benefits over the Company's current billing system, known as CSS. The first is a reduction in the overall operating costs of information systems that provide billing and other customer services for the Company. By moving to one system from the current dual billing systems, per customer operating costs are reduced due to hardware, software licensing and systems support personnel. The second is that a single billing system allows standardization of customer service and billing processes across the XEI utility companies. The third is that a new system enables Xcel Energy to meet new customer need for enhanced access to their accounts through the internet. The legacy CSS billing and customer service system for Xcel Energy do not support any significant

internet customer access, nor is the system amenable to changes of this magnitude.

Q. HOW IS CRS INCLUDED IN THE BUDGET TEST YEAR?

A. The costs of the CRS system were included in the 2004 budget to begin in October. The CRS system has already been implemented in on the Public Service Company of Colorado ("PSCo") and Southwestern Public Service ("SPS") utility systems. The implementation was phased to allow adequate testing and debugging before application to the Company's utility customers in North Dakota, South Dakota and Minnesota. Based on those experiences, the decision was recently made to move back the Dakotas/Minnesota implementation dates to February 2005, to provide greater assurance that the impact on customers would be minimized during the transition to the new billing system.

Q. IS IT APPROPRIATE TO ASSUME, FOR RATEMAKING PURPOSES, THAT CRS IS IN-SERVICE AT THE BEGINNING OF 2004?

A. Yes, the test year rate base is intended to be representative of normal rate base costs. The CRS system will be fully operational before final rates become effective. The previous CSS billing system has been fully depreciated and no rate base amount associated with CSS is included in 2004. Thus, if rates were based on CSS, ratepayers would not pay any costs associated with the annual cost of the billing system actually used to provide service at the time the final rates were in effect. Given that the amounts associated with the adjustment occur before final rates take effect, these known costs can and should be extrapolated to and included in the 2004 test year.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE ADJUSTMENT.

A. The Company calculated all plant related costs and rate base amounts on a forward-looking basis for the year 2005. As such, the beginning rate base was reduced to include three months of book depreciation and the ending rate base was reduced for an additional 12 months of depreciation for a total of 15 months of depreciation. The accumulated deferred tax reduction to rate base was consistent with the accumulated tax depreciation and book depreciation amounts through 2005. The annual cost associated with this project includes 12 months of book depreciation expense. Also, all O&M costs associated with the existing CSS software were removed from the test period data so that only CRS O&M costs remain, which are representative of annual costs going forward. The result of these calculations provides an annualized cost representation of the CRS project.

XIII. INCOME STATEMENT
REVENUES

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR CONSIDERED?

A. Yes. Test year retail sales levels assume normal weather. The test year sales volumes were shown in Schedule 5 of the Notice of Change in Rates.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE TEST YEAR?

A. Yes. This adjustment is incorporated into retail sales forecast, the effect of which is to project the level of revenues on a calendar-month basis.

Q. HAS THE COMPANY MADE SIMILAR ADJUSTMENTS IN PRIOR RATE CASES TO RECOGNIZE THE NET CHANGE IN UNBILLED REVENUES DURING THE TEST YEAR?

A. Yes. The adjustment is consistent with the methodology in the last two NSP North Dakota gas rate cases, Case Nos. PU-400-00-521 and PU-400-95-559.

Q. WHAT IS THE PURPOSE OF MAKING AN UNBILLED REVENUE CALCULATION IN THE TEST YEAR?

A. The unbilled revenue calculation is used to determine the total revenue requirement for gas operations in the North Dakota jurisdiction. Including unbilled revenues in the determination of revenue requirements reflects a proper matching of revenues with expense on a calendar year basis.

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The test-year includes the net margins associated with a variety of services such as Limited Firm Service propane sales, late payments, locating and balancing service and sales related to storage optimization consistent with previous treatment in the 2000 gas rate case. Revenues from curtailment penalties charged to retail customers and capacity release sales will be returned to customers through the Cost of Gas adjustment mechanism consistent with Commission precedent. No revenues are included for sales of propane as the Company plans to terminate this function going forward. Similarly, the off-system end-user program for the sale of capacity releases was terminated in 2000 and therefore had no impact on the test year. The Company continues to receive revenues from Northern States Power Company (Wisconsin) for

the joint use for the Company's Supervisory Control And Data Acquisition (SCADA) System. However, due to the sale of Viking Gas Transmission Company ("Viking"), SCADA related revenues from Viking have ceased.

OPERATING AND MAINTENANCE EXPENSES
COST OF GAS BUDGET ("COGB")

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR COGB?

A. Normal temperatures are used to develop the sales forecast that in turn serves as the basis for budgeted wholesale natural gas supply purchases.

Q. IF THERE ARE DEVIATIONS FROM THE COGB, HOW ARE CUSTOMERS AFFECTED?

A. The Company's COG tariff mechanism automatically flows through monthly supply cost changes, as well as any impact from a change in contract demand entitlements. The Company formulates its heating supply plan for its North Dakota and Minnesota gas utility operations to be dispatched as a single operated system. The Company's gas supply plan is subject to extensive review by the MPUC and Minnesota Department of Commerce pursuant to MPUC rules. Applying the COG tariff in the billing process seldom results in the precise recovery of the COG because there will always be some over or under collection of gas costs in each jurisdiction due to abnormal weather. Consequently, there is also an annual COG true-up in each jurisdiction. The annual COG true-up is also used to flow through to firm rate classes revenues from any pipeline capacity release sales activities.

ADVERTISING ADJUSTMENT

Q. WHAT IS THE LEVEL OF ADVERTISING EXPENSE INCLUDED IN THE TEST YEAR?

A. The Projected Year advertising expenses for the North Dakota jurisdiction are $77,207, of which $37,497 has been included in the test year. The primary driver of the includable advertising costs is safety at $11,608. The remaining $25,889 is made up of the following categories: $15,337 for General Advertising, and $10,552 for Customer Programs.

Of the $39,710 being excluded, the Company has excluded the entire Brand and Image advertising budget totaling $39,595. This determination was based on our JDE Object Account 723710 "Brand/Image Advertising"; which includes costs associated with television, print, radio and outdoor advertisement and is used by the Brand Advertising Department.

DEPRECIATION EXPENSE

Q. PLEASE IDENTIFY THE DOCKETS ASSOCIATED WITH THE DEPRECIATION RATES USED IN THIS PROCEEDING.

A. Depreciation Expense for the test year reflects the depreciation rates last certified by the MPUC and is consistent with the ongoing practice followed by the Company in North Dakota rate case proceedings.

Q. DID YOU ADJUST INITIAL TEST YEAR BOOK DEPRECIATION EXPENSE?

A. Yes, I made an adjustment totaling $85,000 on an annual basis to the North Dakota jurisdiction. The adjustment was made to reflect a full-year's

depreciation related to the Customer Records System ("CRS") Software discussed above, that was initially budgeted to be activated for North Dakota and Minnesota customers in October. CRS Software is being amortized on the basis of a seven-year period.

CHARITABLE CONTRIBUTIONS

Q. HAVE YOU INCLUDED AMOUNTS IN THE TEST YEAR COST OF SERVICE RELATED TO CHARITABLE CONTRIBUTIONS AND ORGANIZATION DUES?

A. Yes. The Company is proposing to include fifty percent of charitable contributions attributable to the State of North Dakota in the test year. Contributions made by the Company during 2003 were used as a proxy for the 2004 test year. An analysis was performed on contribution detail to insure that only amounts contributed to charities and institutions that could be associated with the gas service territory in the North Dakota jurisdiction were included in the cost of service.

INCENTIVE COMPENSATION / RESTRICTED STOCK PLAN

Q. PLEASE SUMMARIZE ADJUSTMENTS MADE TO THE TEST YEAR COST OF SERVICE TO EXCLUDE COSTS FOR PARTS OF THE INCENTIVE COMPENSATION PROGRAMS.

A. Related to the incentive compensation programs of the Company, test period adjustments were made to exclude the long-term part of the officer's incentive compensation, to remove non-corporate incentive plan costs, to increase the amount of incentive plan costs in the initial corporate budget to reflect a full

payout at one hundred percent of target and to remove all incentive plan costs above twenty-five percent of base pay that were included at the full payout (one hundred percent) of target level. The incentive compensation adjustments are shown on Exhibit___(JCR-1), Schedule 3.

RATE CASE EXPENSE

Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSE IN THIS PROCEEDING.

A. The amortization includes $60,000 of projected direct expenses associated with this notice of rate change docket. In settlement of its last North Dakota gas rate case (Case No. PU-400-00-521), the Company agreed to forgo an amortization in cost of service, and recovery in rates, to collect rate case expenses that were projected at $50,000. An amount based on a three-year amortization of projected costs is proposed for inclusion in the cost of service with no rate base treatment of the unamortized balance. Three years is reasonable because the Company expects to file its next gas rate case in approximately three years.

ENVIRONMENTAL COMPLIANCE

Q. DOES THE COST OF SERVICE INCLUDE DEFERRED COSTS FOR REMEDIATION OF MANUFACTURED GAS PLANT (MGP) OR ENVIRONMENTAL CLEAN-UP SITES?

A. There is no amortization of MGP clean up costs included in the cost of service. There are, however, deferred environmental compliance costs on the

books of the Company that is associated with the former MGP site located in Grand Forks, North Dakota and gas utility operations. As of December 31, 2003, $1,981,000 of unamortized environmental compliance costs remained. The Company is therefore proposing to include the average unamortized balance of environmental compliance costs for the test year of $1,801,000 in rate base.

In the last gas rate case, Case No. PU-400-00-521, the Commission authorized the Company to amortize $2.88 million of MGP remediation costs over eight years starting September 1, 2001, with no rate base treatment of the unamortized balance or the accumulated deferred income taxes associated with the MGP investment. The Settlement Agreement in the case provided that the MGP cost recovery was to occur through an adjustment to the Company's annual PGA true-up adjustment for all rate schedules subject to a cost of gas charge. The annual MGP amortization of $360,000 is included in the calculation of the PGA true-up, which is modified each September 1st and applied as part of the monthly Cost of Gas adjustment. The Settlement Agreement also provided that the Company establish a resource adjustment tariff and billing line item for all current and future transportation service rate schedules at a rate equivalent to the MGP factor included in the effective MGP true-up. The MGP recovery treatment as ordered in the last gas rate case has been carried through in this filing with no modification.

In this case the Company is proposing to include the unamortized balance of MGP costs incurred in rate base to recognize the Company's investment in this clean-up and the time value of money by allowing carrying charges. The determination of revenue requirements and the resulting revenue deficiency is

affected by the Company's proposal to include the average unamortized MGP clean-up cost balance in rate base.

LOBBYING EXPENSES

Q. HOW ARE THE COSTS OF LOBBYING ACTIVITIES TREATED IN THIS APPLICATION?

A. Lobbying costs are recorded as non-operating expenses below-the-line and are not included in the cost of service.

AGENCY SERVICES

Q. DOES NSP PROVIDE AN "AGENCY GAS" SERVICES PROGRAM?

A. No. NSP formally discontinued its agency gas program at the end of the 2002-03 heating season. NSP has one agency-supply arrangement remaining with a single Twin Cities located end-user, whereby the Company acts as an agent on behalf of that end-user, to purchase and transport gas independent of its sales service function. This contractual arrangement exists in the Minnesota jurisdiction and has no impact on the North Dakota jurisdiction's cost of service.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company d/b/a Xcel Energy - Notice of Change in Rates For Natural Gas Service	))))	Case No. PU-400-04-578

AFFIDAVIT OF
Jeffrey C. Robinson

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Jeffrey C. Robinson

Subscribed and sworn to before me, this 1st day of Dec., 2004.

Barbara J. Bridgeman
Notary Public

BARBARA J BRIDGEMAN
NOTARY PUBLIC – MINNESOTA
MY COMMISSION EXPIRES 1-31-2005

Manager
Revenue Analysis
September, 1972

Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, Minnesota 55401

Current Responsibilities
Since 1994, I have been the manager of Revenue Analysis. In this position am responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for electric and gas rates filed on behalf of Northern States Power Company d/b/a Xcel Energy with the North Dakota Public Service Commission, the Minnesota Public Utilities Commission (MPUC), the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission (FERC).

Previous Employment (1972-1994)
Operations Analyst - Northern States Power Company
Tax Depreciation Analyst - NSP
Manager, Depreciation Services - NSP
Manager, Depreciation & Nuclear Fuel Accounting - NSP
Manager, Corporate Economics and Depreciation - NSP
Manager, Capital Asset Accounting – NSP
Manager, Revenue Requirements - NSP

Education
University of Wisconsin, River Falls - Bachelor of Science
Major - Mathematics

Certifications
Certified Depreciation Professional (1997-2003)

Professional Associations and Registrations
Past Chair - Edison Electric Institute, Depreciation Accounting Committee (1984-1985)
Society of Depreciation Professionals

Articles or Papers Published or Presented
Jeffrey C. Robinson, "A Sinking Fund Approach to Nuclear Fuel Disposal Recovery," Iowa State University Regulatory Conference 1980 - Vol. 19. May 1980.

Jeffrey C. Robinson, "A Sinking Fund Approach to Nuclear Fuel Disposal Recovery," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administration Year 1980 -1981, Vol. 2, June 1980.

Jeffrey C. Robinson, "Mechanized Depreciation Accounting Systems," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administrative Year 1980-1981, Vol. 2, February 1981.

Jeffrey C. Robinson, "Revenue Requirements Related to Unit-Of-Production Depreciation," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administrative Year 1981-1982, Vol. 3, February 1982.

Jeffrey C. Robinson and Cheryl R. Hatfield, "Economic Comparison of Nuclear Decommissioning Funding Alternatives," Proceedings of the A.G.A. Depreciation and EEI Depreciation Accounting Committee, Administrative Year 1986-1987, Vol. 8, September, 1987.

Jeffrey C. Robinson, "Economic Evaluation of Power Plant Life Extension," Proceedings of the A.G.A. Depreciation and EEI Depreciation Accounting Committee, Administrative Year 1987-1988, Vol. 9, September, 1988.

Previous Testimony
FERC, Nuclear Fuel Disposal, Docket No. ER81-651-000, 1981
FERC, Nuclear Fuel Disposal, Docket No. ER81-653-000, 1981
FERC, Tax Normalization, Docket No. ER88-72-000, 1988
FERC, Nuclear Decommissioning, Docket No. ER88-75-000, 1988

Minnesota, Ramsey County District Court, Depreciation, File No. 456710, 1984
Minnesota, Nuclear Decommissioning, Docket No. E002/GR-87-670, 1987
Minnesota, Nuclear Decommissioning, Docket No. E002/GR-89-865, 1989
Minnesota, Nuclear Fuel Storage, Docket No. E002/CN-91-19, 1991
Minnesota, Depreciation and Nuclear Decommissioning, Docket No. E002/GR-92-1185, 1992
Minnesota, Pre-Merger Revenue Requirements, Merger Rate Plan, Savings Allocations, Docket No. E,G-002/PA-95-500, 1995
Minnesota, Rate Base, Docket No. G002/GR-97-1606, 1997
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-04-1511, 2004

North Dakota, Depreciation, Docket No. 10,979, 1987

South Dakota, Nuclear Decommissioning, Docket No. F-3764, 1988

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
SUMMARY OF TRADITIONAL REGULATORY & DATA REVIEW ADJUSTMENTS
Test Year Ending December 31, 2004
($000's)

	Adjustment Description	Adjustment Target	Total Company	ND Jurisdiction	Allocation Method
1	Charitable Contributions	Administrative & General	200	29	Direct/Customer
2	Advertising Expenses	Administrative & General	(776)	(40)	Direct/Customer
3	Professional Assn & Utility Assn Dues	Administrative & General	(8)	(1)	Customer
4	Economic Development Costs	Administrative & General	9	6	Direct/Customer
5	Tax Benefit Transfer Leases	Administrative & General	(3)	-	Customer
6	Interest on Customer Deposits	Administrative & General	13	5	Customer
7	Legal Costs Associated With Claims	Administrative & General	(87)	(5)	Customer
8	Federal Affairs Adjustment	Administrative & General	(8)	(1)	Customer
9	Allocation Adjustment SD	Administrative & General	(6)	-	Direct
10	Total Adminstrative & General	Administrative & General	(666)	(7)	
11	Public Damage - G/E Locating	Distribution Expense	(400)	(36)	Customer
12	Meter Shop Labor - G/E Assignment	Distribution Expense	(536)	(49)	Customer
13	Reliability Costs - Unsupported	Distribution Expense	(450)	(41)	Customer
14	Non-Gratutious Credits	Distribution Expense	(280)	(25)	Customer
15	Allocation Adjustment SD	Distribution Expense	(15)	-	Direct
16	Total Distribution Expense	Distribution Expense	(1,681)	(151)	
17	Allocation Adjustment SD	Payroll Tax	(2)	-	Direct
18	Remove Promotional Items	Sales Expense	(12)	-	Direct
19	Allocation Adjustment SD	Customer Accounting	(194)	-	Direct
20	Reclassification	Sales Expense	(849)	-	Direct
21		Cust Service & Info Expense	849	-	Direct
22		Net	-	-	
	SCADA	Rate Base			
23		BOY CWIP	-	-	Customer
24		EOY CWIP	-	-	Customer
25		BOY Plant In Service	(1,667)	(151)	Customer
26		EOY Plant In Service	(1,667)	(151)	Customer
27		BOY Depreciation Reserve	-	-	Customer
28		EOY Depreciation Reserve	(185)	(17)	Customer
29		BOY Accumulated Deferred Taxes	-	-	Customer
30		EOY Accumulated Deferred Taxes	(22)	(2)	Customer
		Income Statement			
31		Book Depreciation Expense	(185)	(17)	Customer
32		Deferred Tax Expense	(22)	(2)	Customer
33		AFUDC	-	-	Customer
34		Tax Depreciation (Schedule M)	(238)	(22)	Customer
35		Tax Addition	-	-	Customer

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
SUMMARY OF TRADITIONAL REGULATORY & DATA REVIEW ADJUSTMENTS
Test Year Ending December 31, 2004
($000's)

	Adjustment Description	Adjustment Target	Total Company	ND Jurisdiction	Allocation Method
	Financial Governance - CFM	Rate Base			
1		BOY CWIP	-	-	Customer
2		EOY CWIP	(3)	-	Customer
3		BOY Plant In Service	-	-	Customer
4		EOY Plant In Service	(818)	(74)	Customer
5		BOY Depreciation Reserve	-	-	Customer
6		EOY Depreciation Reserve	(14)	(1)	Customer
7		BOY Accumulated Deferred Taxes	-	-	Customer
8		EOY Accumulated Deferred Taxes	(39)	(4)	Customer
		Income Statement			
9		Book Depreciation Expense	(14)	(1)	Customer
10		Deferred Tax Expense	(39)	(4)	Customer
11		AFUDC	(44)	(4)	Customer
12		Tax Depreciation (Schedule M)	(136)	(12)	Customer
13		Tax Addition	-	-	Customer
	Total Capital Related Adjustments	Rate Base			
14		BOY CWIP	-	-	
15		EOY CWIP	(3)	-	
16		BOY Plant In Service	(1,667)	(151)	
17		EOY Plant In Service	(2,485)	(225)	
18		BOY Depreciation Reserve	-	-	
19		EOY Depreciation Reserve	(199)	(18)	
20		BOY Accumulated Deferred Taxes	-	-	
21		EOY Accumulated Deferred Taxes	(61)	(6)	
		Income Statement			
22		Book Depreciation Expense	(199)	(18)	
23		Deferred Tax Expense	(61)	(6)	
24		AFUDC	(44)	(4)	
25		Tax Depreciation (Schedule M)	(374)	(34)	
26		Tax Addition	-	-	
27	Hedging	Prepaid & Other BOY&EOY	2,588	284	Design Day
28	Miscellaneous Debits & Credits	Prepaid & Other BOY&EOY	1,733	235	Direct/Customer/Labor

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
Test Year Ending December 31, 2004
($000's)

Case No PU 400-04-578
Exhibit___(JCR-1), Schedule 3

	Adjustment Description	Adjustment Target	Total Company	ND Jurisdiction	Allocation Method
1	Revised Sales Forecast	Retail Revenues	85,503	8,971	Direct
2		Transportation Revenues	(134)	44	Direct
3		Purchased Cost of Gas	(87,628)	(9,088)	Direct
4		Net	(2,259)	(73)	
5	Adjust CIP Revenues to have Revenues	Retail Revenues	(2)	-	Direct
6	equal progam costs	Transportation Revenues	43	-	Direct
7		Total	41	-	
8	Bundled Sales Adjustment	Retail Revenues - Other	14,042	1,475	Direct
9		Purchased Cost of Gas	(13,544)	(1,422)	Direct
10		Net	498	53	
11	Removal of Propane	Other Revenues - Limited Firm Sales	(305)	(12)	Design Day
12		Purchased Cost of Gas	200	6	Design Day
13		Net	(105)	(6)	
14	Sales to Other - MN LP	Sales to Other - MN LP	(490)	(54)	Design Day
15	Total Net Margin Revenue Adjustment	Revenues	(2,315)	(80)	
	Incentive Compensation				
16	Base Plan @ 100% of Target	Administrative & General	576	49	Customer/Labor
17	Amounts in Excess of 25%	Administrative & General	(88)	(7)	Customer/Labor
18	Area Specific Plans	Administrative & General	(53)	(4)	Customer/Labor
19	Long Term Incentive Plans	Administrative & General	(554)	(50)	Customer/Labor
20	Net Incentive Comp Adjustment	Administrative & General	(119)	(12)	
21	Removal of Propane	Distribution Expense	(32)	(3)	Customer
22	Remove CSS O&M Costs	Customer Accounting - FERC 903	(250)	(23)	Customer
23	CRS 2005 O&M	Customer Accounting	331	30	Customer
24	Meter Calibration	Other Revenue	159	41	Direct
25	Balancing Service Revenue	Other Revenue	30	30	Direct
	Rate Case Expense Amortization	Rate Base			
26		BOY CWIP	-	-	Direct
27		EOY CWIP	-	-	Direct
28		BOY Plant In Service	-	-	Direct
29		EOY Plant In Service	-	-	Direct
30		BOY Depreciation Reserve	-	-	Direct
31		EOY Depreciation Reserve	-	-	Direct
32		BOY Accumulated Deferred Taxes	-	-	Direct
33		EOY Accumulated Deferred Taxes	-	-	Direct
34		BOY Prepaid & Other	-	-	Direct
35		EOY Prepaid & Other	-	-	Direct
		Income Statement			
36		O&M Amortization	20	20	Direct
37		Deferred Tax Expense	-	-	Direct
38		AFUDC	-	-	Direct
39		Tax Depreciation (Schedule M)	-	-	Direct
40		Tax Addition	20	20	Direct
	Gas Clean Up Amortization	Rate Base			
41		BOY CWIP	-	-	Direct
42		EOY CWIP	-	-	Direct
43		BOY Plant In Service	-	-	Direct
44		EOY Plant In Service	-	-	Direct
45		BOY Depreciation Reserve	-	-	Direct
46		EOY Depreciation Reserve	-	-	Direct
47		BOY Accumulated Deferred Taxes	808	808	Direct
48		EOY Accumulated Deferred Taxes	662	662	Direct
49		BOY Prepaid & Other	1,981	1,981	Direct
50		EOY Prepaid & Other	1,621	1,621	Direct
		Income Statement			
51		O&M Amortization	360	360	Direct
52		Deferred Tax Expense	(147)	(147)	Direct
53		AFUDC	-	-	Direct
54		Tax Depreciation (Schedule M)	-	-	Direct
55		Tax Addition	360	360	Direct

Northern States Power Company (Minnesota) d\b\a Xcel Energy
Gas Utility - State of North Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
Test Year Ending December 31, 2004
($000's)

	Adjustment Description	Adjustment Target	Total Company	ND Jurisdiction	Allocation Method
	Annualize CRS - Full Year	Rate Base			
1		BOY CWIP	(5,637)	(512)	Customer
2		EOY CWIP	-	-	Customer
3		BOY Plant In Service	8,483	771	Customer
4		EOY Plant In Service	-	-	Customer
5		BOY Depreciation Reserve	(277)	(25)	Customer
6		EOY Depreciation Reserve	658	60	Customer
7		BOY Accumulated Deferred Taxes	-	-	Customer
8		EOY Accumulated Deferred Taxes	(332)	(30)	Customer
		Income Statement			
9		Book Depreciation Expense	935	85	Customer
10		Deferred Tax Expense	(332)	(30)	Customer
11		AFUDC	(398)	(36)	Customer
12		Tax Depreciation (Schedule M)	122	11	Customer
13		Tax Addition	-	-	Customer
	New Business CIAC	Rate Base			
14		BOY CWIP	-	-	Direct
15		EOY CWIP	-	-	Direct
16		BOY Plant In Service	(2,366)	-	Direct
17		EOY Plant In Service	(2,366)	-	Direct
18		BOY Depreciation Reserve	-	-	Direct
19		EOY Depreciation Reserve	(72)	-	Direct
20		BOY Accumulated Deferred Taxes	-	-	Direct
21		EOY Accumulated Deferred Taxes	(472)	-	Direct
		Income Statement			
22		Book Depreciation Expense	(72)	-	Direct
23		Deferred Tax Expense	(472)	-	Direct
24		AFUDC	-	-	Direct
25		Tax Depreciation (Schedule M)	(1,227)	-	Direct
26		Tax Addition	-	-	Direct
*	Total Capital Related Adjustments	Rate Base			
27		BOY CWIP	(5,637)	(512)	
28		EOY CWIP	-	-	
29		BOY Plant In Service	6,117	771	
30		EOY Plant In Service	(2,366)	-	
31		BOY Depreciation Reserve	(277)	(25)	
32		EOY Depreciation Reserve	586	60	
33		BOY Accumulated Deferred Taxes	808	808	
34		EOY Accumulated Deferred Taxes	(142)	632	
35		BOY Prepaid & Other	1,981	1,981	
36		EOY Prepaid & Other	1,621	1,621	
		Income Statement			
37		O&M Amortization	380	380	
38		Book Depreciation Expense	863	85	
39		Deferred Tax Expense	(951)	(177)	
40		AFUDC	(398)	(36)	
41		Tax Depreciation (Schedule M)	(1,105)	11	
42		Tax Addition	380	380	

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
SUMMARY OF REVENUE REQUIREMENTS
Test Year Ending December 31, 2004
($000's)

Case No. PU 400-04-578
Exhibit___(JCR-1), Schedule 4

Line	Description	North Dakota Jurisdiction
1	Average Rate Base	$42,398
2	Operating Income (Before AFUDC)	$3,224
3	Allowance for Funds Used During Construction	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$3,224
5	Overall Rate of Return (Line 4 / Line 1)	7 60%
6	Required Rate of Return	9 43%
7	Operating Income Requirement (Line 1 x Line 6)	$3,998
8	Income Deficiency (Line 7 - Line 6)	$774
9	Gross Revenue Conversion Factor	1 65426
10	Revenue Deficiency (Line 8 x Line 9)	$1,280
11	Retail Related Revenue Under Present Rates	$68,841
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	1 86%

ROE = 7.87%
Deficiency = $1,280
% Increase = 1.86%
Required ROE = 11.50%

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Test Year

Summary Reports

October 26, 2004

Printed 10/26/2004 1:53 PM

Rate Base Summary

		Total Company Gas			North Dakota Retail Gas			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	795,836	847,026	821,431	72,704	77,377	75,041	723,132	769,649	746,390
2	Depreciation Reserve	(340,180)	(369,926)	(355,053)	(31,329)	(34,034)	(32,682)	(308,851)	(335,892)	(322,371)
3	Net Utility Plant	455,656	477,100	466,378	41,375	43,343	42,359	414,281	433,757	424,019
4	C W I P	659	834	747	118	84	101	541	750	646
5	Accumulated Deferred Taxes	(62,585)	(68,608)	(65,597)	(5,652)	(6,234)	(5,943)	(56,933)	(62,374)	(59,654)
	Other Rate Base									
6	Cash Working Capital	(8,675)	(8,675)	(8,675)	(549)	(549)	(549)	(8,126)	(8,126)	(8,126)
7	Materials & Supplies	2,071	2,071	2,071	188	188	188	1,883	1,883	1,883
8	Gas In Storage	34,722	34,722	34,722	3,834	3,834	3,834	30,888	30,888	30,888
9	Non-Plant Assets & Liab	(7,163)	(6,676)	(6,920)	(593)	(556)	(574)	(6,570)	(6,121)	(6,346)
10	Prepaids & Other	13,243	12,883	13,063	3,162	2,802	2,982	10,081	10,081	10,081
11	**Total Rate Base**	**427,928**	**443,651**	**435,789**	**41,883**	**42,912**	**42,398**	**386,046**	**400,739**	**393,391**

Income Statement Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Operating Revenues			
1	Retail	659,264	68,678	590,586
2	Net Margin Weather Adjustment	0	0	0
3	Interdepartmental & Transportation	8,702	163	8,539
4	Other Operating	18,273	1,787	16,486
5	Gross Earnings Tax	7,536	979	6,557
6	**Total Operating Revenues**	**693,776**	**71,607**	**622,169**
	Expenses			
	Operating Expenses			
7	Purchased Gas	534,510	57,267	477,243
8	Production	3,678	724	2,953
9	Transmission	869	96	773
10	Distribution	22,917	1,664	21,252
11	Customer Accounting	11,054	1,142	9,913
12	Customer Service & Information	5,961	80	5,881
13	Administrative & General	16,852	1,458	15,394
14	Amortizations	252	20	232
15	Sales, Econ Dvlp & Other	239	131	108
16	Total Operating Expenses	596,331	62,582	533,750
17	Depreciation	29,665	2,698	26,967
	Taxes			
18	Property	13,234	1,003	12,232
19	Gross Earnings	7,536	979	6,557
20	Deferred Income Tax & ITC	5,691	551	5,140
21	State & Federal Income (see Page 3)	4,886	408	4,478
22	Payroll & Other	2,160	163	1,997
23	Total Taxes	33,507	3,104	30,404
24	**Total Expenses**	**659,503**	**68,383**	**591,120**
25	AFUDC	0	0	0
26	**Total Operating Income**	**34,273**	**3,224**	**31,049**

Income Tax Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Income Before Taxes			
1	Total Operating Revenues	693,776	71,607	622,169
2	less Total Operating Expenses	(596,331)	(62,582)	(533,750)
3	Book Depreciation	(29,665)	(2,698)	(26,967)
4	Taxes (Other Than Current Income)	(28,621)	(2,696)	(25,926)
5	**Total Before Tax Book Income**	**39,158**	**3,632**	**35,526**
	Tax Additions			
6	Book Depreciation	29,665	2,698	26,967
9	Book Depreciation Cleared To Operating	858	78	780
10	Deferred Income Taxes & ITC	5,691	551	5,140
11	Book Amortizations	20	20	0
12	Connection Fees	888	81	807
13	Avoided Tax Interest	1,157	106	1,051
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	38	3	35
16	TBT Net Expense	(3)	0	(3)
17	**Total Tax Additions**	**38,314**	**3,537**	**34,777**
	Tax Deductions			
18	Tax Depreciation & Removal Expense	50,107	4,664	45,443
19	Debt Interest Expense	15,915	1,548	14,366
20	Other Tax/Book Timing Differences	(520)	(75)	(445)
21	Net Preferred Stock Deduction	0	0	0
22	**Total Tax Deductions**	**65,502**	**6,137**	**59,364**
23	**State Taxable Income**	**11,971**	**1,032**	**10,939**
24	State Income Tax Rate	8 95%	7 00%	N/A
25	**Total State Income Taxes**	**1,071**	**72**	**999**
26	**Federal Taxable Income**	**10,900**	**959**	**9,941**
27	Federal Income Tax Rate	35 00%	35 00%	35 00%
28	**Total Federal Income Taxes**	**3,815**	**336**	**3,479**
29	**Total Federal & State Income Taxes**	4,886	408	4,478

Revenue Requirement & Return Summary

(Dollars in Thousands)

	2004 Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	7 3300%	48 6530%	3 5663%
2	Short Term Debt	7 7400%	1 1070%	0 0857%
3	Preferred Stock	0 0000%	0 0000%	0 0000%
4	Common Equity	11 5000%	50 2400%	5 7776%
5	**Required Rate of Return**			**9.4295%**

	Composite Income Tax Rates		
	State of North Dakota Tax rate		7 00%
	Federal Statutory Tax rate	35 00%	
	Federal Effective Tax Rate (1-State Rate * Fed Rate)		32 55%
	Total North Dakota Composite Tax Rate		**39.55%**
	Total Corporate Composite Tax Rate		**40.81%**

		Total Company Gas	North Dakota Retail Gas	All Other
	Rate of Return (ROR)			
6	Total Operating Income	34,273	3,224	31,049
7	Total Average Rate Base	435,789	42,398	393,391
8	**ROR (Operating Income / Rate Base)**	**7.86%**	**7.60%**	**7.89%**
	Return on Equity (ROE)			
9	Total Operating Income	34,273	3,224	31,049
10	Debt Interest (Rate Base * Weighted Debt Cost)	(15,915)	(1,548)	(14,366)
11	Preferred Stock (Rate Base * Weighted Preferred Cos	0	0	0
12	Earnings Available for Common	18,358	1,676	16,682
13	Equity Rate Base (Rate Base * Equity Ratio)	218,940	21,301	197,640
14	**ROE (Earnings for Common / Equity Rate Base)**	**8.38%**	**7.87%**	**8.44%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Ret	41,093	3,998	37,095
16	Operating Income	34,273	3,224	31,049
17	Operating Income Deficiency	6,820	774	6,046
18	Revenue Conversion Factor (1/(1-Composite Tax Rat	1 68960	1 65426	N/A
19	**Revenue Deficiency (Income Deficiency * Conversion**	**11,523**	**1,280**	**10,243**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	667,967	68,841	599,126
21	Revenue Deficiency	11,523	1,280	10,243
22	**Total Retail Revenue Requirements**	**679,490**	**70,122**	**609,368**
23	**Percentage Increase (Decrease)**	**1.73%**	**1.86%**	**1 71%**

Rate Base Detail - Cash Working Capital

				Total Company Gas			North Dakota Retail Gas			All Other	
	Expenses										
	Includable Expenses		**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Purchased Gas										
1	Purchases		40 25	534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
2	Subtotal Purchased Gas			534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
	Labor & Related Costs										
3	Regular Payroll		13 79	32,344	446,018		2,721	37,523		29,623	408,496
4	Incentive Compensation		259 51	1,148	297,831		99	25,691		1,049	272,139
5	Pension & Benefits		29 79	4,916	146,447		354	10,546		4,562	135,901
6	Subtotal Labor & Related			38,407	890,296		3,174	73,760		35,233	816,536
7	All Other Operating Expenses		42 34	23,162	980,685		2,121	89,801		21,041	890,884
8	Property Tax		345 46	13,234	4,571,948		1,003	346,422		12,232	4,225,525
9	Employer's Payroll Taxes		19 66	2,160	42,459		163	3,198		1,997	39,261
10	Gross Earnings Tax		71 98	7,536	542,453		979	70,474		6,557	471,979
11	Federal Income Tax		37 00	3,815	141,154		336	12,424		3,479	128,731
12	State Income Tax		37 00	1,071	39,621		72	2,672		999	36,949
13	State Sales Tax Customer Billings		51 86	13,668	708,843		1,111	57,616		12,557	651,227
14	Total Expenses		46 16	637,564	29,431,491	44 72	66,225	2,961,356	46 33	571,339	26,470,135
15	**Net Annual Expense Amount**				80,634			8,113			72,521
	Revenues		**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
16	Computer Billing	100 00%	41 94	659,264	27,649,551		68,678	2,880,359		590,586	24,769,192
17	Hand Billed	0 00%	41 94	0	0		0	0		0	0
18	Retail Revenue Adjustments		41 94	0	0		0	0		0	0
19	Interdepartmental		0 00	7,104	0		10	0		7,094	0
20	Transportation		33 21	1,598	53,078		153	5,076		1,445	48,001
21	Late Payment		0 00	2,293	0		131	0		2,162	0
22	Meter Calibration Adjustment		41 94	159	6,668		41	1,720		118	4,949
23	Connect Charge		41 94	456	19,131		45	1,906		411	17,225
24	Return Check Charge		41 94	37	1,550		2	71		35	1,479
25	Rents - Gas Property		35 21	0	0		0	0		0	0
26	CIP - Lost Sales Margin		0 00	0	0		0	0		0	0
27	Gas Agreement		35 21	239	8,428		26	926		213	7,502
28	Locating Services		35 21	0	0		0	0		0	0
29	Balancing Service		35 21	30	1,056		30	1,056		0	0
30	Standby Sales Res & Vols		35 21	0	0		0	0		0	0
31	Limited Firm Sales - Res & Vols		35 21	917	32,272		37	1,301		880	30,971
32	Sales to Other - MN LP		35 21	0	0		(0)	(8)		0	8
33	Off System End User		35 21	0	0		0	0		0	0
34	Opportunity Sales		35 21	14,042	494,419		1,475	51,935		12,567	442,484
35	CIAC Gross-Up		0 00	0	0		0	0		0	0
36	Agency Service		0 00	0	0		0	0		0	0
37	Other Gas Revenue		41 94	100	4,197		0	0		100	4,197
38	Total Revenues		41 20	686,240	28,270,351	41 69	70,628	2,944,342	41 14	615,812	25,326,009
39	Net Annual Amount				77,453			8,067			69,386
40	Expense / Revenue Factor				0 929068739			0 937660736			
41	**Allocated Revenue Amount**				71,959			7,564			
42	**Net Cash Working Capital**		Page 1 - Line 6		(6,675)			(549)			(6,126)

Line	Summary of Major Cost Elements of the Revenue Deficiency	Revenue Deficiency (millions)
1	Capital Recovery for additional rate base investment (includes return requirement, change in cost of capital and depreciation)	$ 1 853
	Operating Expenses	
2	Production, Transmission and Distribution Operations	(0 091)
3	Customer Accounts	0 454
4	Customer Services, Sales and Administrative and General Expense	(0 332)
5	Total Operating Expenses	0 031
	Other	
6	Payroll Taxes	(0 081)
7	Real Estate and Personal Property	0 026
8	Rate Case Expense	0 020
9	Subtotal	1 849
10	Less, Net Sales Growth	(0 569)
11	Net Revenue Deficiency	$ 1 280

Summary of Test Year O & M Expense Changes
Since Last Authorized Rate Increase, Case No PU 400-00-521
Shown by Functional Grouping, Gross Dollar Change and
Average Annual Percentage Change
(dollars in thousands 000's)

Line	Functional Class	Increase (Decrease)	Average Annual %
1	Production, Storage, and Transmission Expense	$ (163)	-6 5%
2	Distribution and Maintenance Expense	72	1 1%
3	Customer Accounting	454	16 5%
4	Customer Services and Sales Expenses	(311)	-14 9%
5	Administrative and General Expenses	(21)	-0 4%
6	Total Operating Expenses	$ 31	0 2%

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
OPERATING REVENUES, OPERATING EXPENSE, TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
Test Year Ending December 31, 2004
(Dollars in Thousands)

Line No.	Description	Test Year Ending 12/31/04 Present Rates (A)	Final Increase (B)	Test Year Ending 12/31/04 Final Rates (C) = (B) + (A)
	Operating Revenues			
1	Retail	$68,678	$1,280	$69,958
2	Weather Impact Net Margin Adjustment	0		0
3	Interdepartmental & Transportation	163		163
4	Other Operating	1,787		1,787
5	Gross Earnings Tax	979		979
6	**Total Operating Revenues**	$71,607	$1,280	$72,887
	Expenses			
	Operating Expenses			
7	Purchased Gas	$57,267		$57,267
8	Other Production	724		724
9	Transmission	96		96
10	Distribution	1,664		1,664
11	Customer Accounting	1,142		1,142
12	Customer Service & Information	80		80
13	Administrative & General	1,458		1,458
14	Amortizations	20		20
15	Sales, Econ Dvlp & Other	131		131
16	Total Operating Expenses	$62,582	$0	$62,582
17	Depreciation	$2,698	$0	$2,698
	Taxes			
18	Property	$1,003		$1,003
19	Gross Earnings	979		979
20	Deferred Income Tax & ITC	551		551
21	Federal & State Income Tax	408	506	914
22	Payroll & Other	163		163
23	Total Taxes	$3,103	$506	$3,609
24	**Total Expenses**	$68,383	$506	$68,889
25	AFUDC	$0	$0	$0
26	**Total Operating Income**	$3,224	$774	$3,998

Note Revenues reflect calendar month sales

Northern States Power Company (Minnesota) d/b/a Xcel Energy
Gas Utility - State of North Dakota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME
($000's)

Case No PU 400-04-578
Exhibit___(JCR-1), Schedule 7
Page 2 of 2

Line No.	Description	Proposed Test Year 2004 Unadjusted Total Utility (E)	Unadjusted North Dakota Jurisdiction (F)	Adjustments (G)	Proposed North Dakota Jurisdiction (H) (Col F + G)
	Operating Revenues				
1	Retail	$573,763	$59,707	$8,971	$68,678
2	Weather Impact Net Margin Adjustment	-	-	0	0
3	Interdepartmental & Transportation	8,793	119	44	163
4	Other Operating	4,837	307	1,480	1,787
5	Gross Earnings Tax	7,536	979	0	979
6	**Total Operating Revenues**	$594,929	$61,112	$10,495	$71,607
	Expenses				
	Operating Expenses				
7	Purchased Gas	$433,538	$46,763	$10,504	$57,267
8	Other Production	3,678	724	0	724
9	Transmission	869	96	0	96
10	Distribution	22,949	1,667	(3)	1,664
11	Customer Accounting	10,973	1,135	7	1,142
12	Customer Service & Information	5,961	80	0	80
13	Administrative & General	16,971	1,470	(12)	1,458
14	Amortizations	232	-	20	20
15	Sales, Econ Dvlp & Other	239	131	0	131
16	Total Operating Expenses	$495,410	$52,066	$10,516	$62,582
17	Depreciation	$28,802	$2,613	$85	$2,698
	Taxes				
18	Property	$13,234	$1,003	$0	$1,003
19	Gross Earnings	$7,536	979	0	979
20	Deferred Income Tax & ITC	$6,495	581	(30)	551
21	Federal & State Income Tax	5,295	441	(33)	408
22	Payroll & Other	$2,160	163	0	163
23	Total Taxes	$34,720	$3,167	($63)	$3,104
24	**Total Expenses**	$558,932	$57,846	$10,538	$68,384
25	Allowance for Funds Used During Cons	$0	$0	0	$0
26	**Total Operating Income**	$35,998	$3,267	($43)	$3,224

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
DETAIL OF RATE BASE COMPONENTS
($000's)

Case No. PU-400-04-578
Exhibit___(JCR-1), Schedule 8

Line No.	Description	Proposed Test Year 2004 Average Rate Base (A)
	Gas Plant as Booked	
1	Production	$1,660
2	Storage	3,396
3	Transmission	3,142
4	Distribution	60,231
5	General	1,640
6	Common	4,971
7	TBT Investment	2
8	TOTAL Utility Plant in Service	$75,041
	Reserve for Depreciation	
9	Production	$1,213
10	Storage	2,439
11	Transmission	1,721
12	Distribution	23,745
13	General	969
14	Common	2,595
15	TOTAL Reserve for Depreciation	$32,682
	Net Utility Plant in Service	
16	Production	$447
17	Storage	957
18	Transmission	1,421
19	Distribution	36,486
20	General	671
21	Common	2,376
22	TBT Investment	2
23	Net Utility Plant in Service	$42,359
24	Utility Plant Held for Future Use	$0
25	Construction Work in Progress	$101
26	Less Accumulated Deferred Income Taxes	$5,943
27	Cash Working Capital	($549)
	Other Rate Base Items	
28	Materials and Supplies	$188
29	Gas In Storage	3,834
30	Non-Plant Assets & Liabilities	(574)
31	Prepayments	962
32	Rate Case Expense Amortization	0
33	Gas Clean-Up Amortization	1,801
36	Customer Advances	(16)
37	Other Working Capital	235
38	Total Other Rate Base Items	$6,430
39	Total Average Rate Base	$42,398

Line No	Description	Proposed Test Year 2004					
		Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Gas Plant as Booked						
1	Production	$15,118	$0	$15,118	$1,660	$0	$1,660
2	Storage	30,918	0	30,918	3,396	0	3,396
3	Transmission	30,510	0	30,510	3,142	0	3,142
4	Distribution	674,496	0	674,496	60,231	0	60,231
5	General	16,768	0	16,768	1,524	0	1,524
6	Common	51,723	1,875	53,598	4,700	386	5,086
7	TBT Investment	23	0	23	2	0	2
8	TOTAL Utility Plant in Service	$819,556	$1,875	$821,431	$74,655	$386	$75,041
	Reserve for Depreciation						
9	Production	$11,048	$0	$11,048	$1,213	$0	$1,213
10	Storage	22,208	0	22,208	2,439	0	2,439
11	Transmission	16,709	0	16,709	1,721	0	1,721
12	Distribution	265,907	(36)	265,871	23,745	0	23,745
13	General	10,578	0	10,578	961	0	961
14	Common	28,449	191	28,640	2,585	18	2,603
15	TOTAL Reserve for Depreciation	$354,899	$155	$355,053	$32,664	$18	$32,682
	Net Utility Plant in Service						
16	Production	$4,070	$0	$4,070	$447	$0	$447
17	Storage	8,710	0	8,710	957	-	957
18	Transmission	13,801	0	13,801	1,421	-	1,421
19	Distribution	408,589	36	408,625	36,486	-	36,486
20	General	6,191	0	6,191	564	-	564
21	Common	23,274	1,685	24,958	2,115	368	2,483
22	TBT Investment	23	0	23	2	-	2
23	Net Utility Plant in Service	$464,657	$1,721	$466,378	$41,991	$368	$42,359
24	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
25	Construction Work in Progress	$3,565	($2,819)	$747	$357	($256)	$101
26	Less Accumulated Deferred Income	$65,999	($402)	$65,597	$5,958	($15)	$5,943
27	Cash Working Capital	($8,965)	$290	($8,675)	($579)	$30	($549)
	Other Rate Base Items						
28	Materials and Supplies	$2,071	$0	$2,071	$188	$0	$188
29	Gas In Storage	34,722	0	34,722	3,834	0	3,834
30	Non-Plant Assets & Liabilities	(6,920)	0	(6,920)	(574)	0	(574)
31	Prepayments	5,823	0	5,823	1,075	0	1,075
32	Rate Case Expense Amortization	0	0	0	0	0	0
34	Gas Clean-Up Amortization	0	1,801	1,801	0	1,801	1,801
36	Customer Advances	(177)	0	(177)	(16)	0	(16)
37	Other Working Capital	5,616	0	5,616	122	0	122
38	Total Other Rate Base Items	$41,136	$1,801	$42,937	$4,629	$1,801	$6,430
39	Total Average Rate Base	$434,393	$1,395	$435,789	$40,440	$1,958	$42,398

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules Accounts not on this page have been directly asigned to jurisdiction.	
1	Production & Storage	Design Day Demand
2	Transmission	Load Dispatch
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers
5	Customer Service & Information	Customers
6	Sales, Econ Dvlp & Other	Customers
7	Administrative & General	Customers

Northern States Power Company (MN) d/b/a Xcel Energy
Gas Utility - State of North Dakota
OPERATING INCOME SCHEDULES
OPERATING INCOME JURISDICTIONAL
ALLOCATION FACTOR AMOUNTS

		Test Year 2004		
Line No	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Design Day Demand (1)	677,930	74,462	10 9837%
2	Design Day Demand (1)	677,930	74,462	5 4919%
	MCF	90,161,739	10,034,502	5 5650%
	Load Dispatch (2)			11 0569%
3	Customers (3)	451,304	41,000	9 0848%

(1) Design Day Demand
(2) Average of the Design Day Demand allocation and Total MCF Sales Percentage
(3) Average number of Customers

Line No	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules Accounts not on this page have been directly assigned to jurisdictions	
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress	
1	Production (LPG Production)	Design Day Demand
2	Storage (LNG Storage)	Design Day Demand
3	General	
	Production	Design Day Demand
	Other	Customers
4	Common	
	Production	Design Day Demand
	Other	Customers
	In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts	
5	TBT Investment	Customers
6	Other Rate Base	
	Materials & Supplies	Customers
	Gas in Storage	Design Day Demand
	Gas in Storage-Underground	Load Dispatch
	Non-Plant Assets & Liabilities	Customers and Load Dispatch
	Prepayments - Insurance	Customers
	Prepayments - Gas Reserv Fee	Design Day Demand
	Prepayments - Gas Imbalances	Load Dispatch
	Prepayments - Misc	Customers

		Test Year 2004		
Line No	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Design Day Demand (1)	677,930	74,462	10 9837%
2	Design Day Demand (1)	677,930	74,462	5 4919%
	MCF	90,161,739	10,034,502	5 5650%
	Load Dispatch (2)			11 0569%
3	Customers (3)	451,304	41,000	9.0848%

(1) Design Day Demand
(2) Average of the Design Day Demand allocation and Total MCF Sales Percentage
(3) Average number of Customers

Northern States Power Company
Gas Utility - North Dakota
(Dollars In Thousands)

Case No. PU-400-04-578
Exhibit___(JCR-1), Schedule 11

II. OPERATING INCOME

Line	Item	2003 Total NSP	2003 N.D. Juris.	N. D. %
	Operating Revenues:			
1	Residential	360,410	26,144	7 3%
2	Firm C & I	195,684	28,902	14 8%
3	Interruptible C & I	95,783	11,253	11 7%
4	Transportation/Other	[illegible]	[illegible]	8.5%
5	Total Revenues	680,977	68,783	10 1%
	Operating Expenses:			
6	Production	527,376	55,121	10 5%
7	Transmission	698	73	10 5%
8	Distribution	18,324	1,339	7 3%
9	Customer Billing	11,874	1,216	10 2%
10	Customer Service	5,938	106	1 8%
11	Sales & Marketing	880	88	10 0%
12	Admin. & General	19,068	1,677	8 8%
13	Depreciation & Amortizations	29,339	2,686	9 2%
14	Property Taxes	12,324	1,016	8.2%
15	Other General Taxes [1]	9,618	1,251	13.0%
16	Income Taxes	9,225	859	9 3%
17	Deferred Income Taxes	1,780	142	8 0%
18	Total Expenses:	646,444	65,574	10 1%
19	Regulated Operating Income	34,533	3,209	9 3%

[1] Includes gross earnings taxes (franchise fees) and payroll taxes

Northern States Power Company
Gas Utility - North Dakota
(Dollars In Thousands)

Case No. PU-400-04-578
Exhibit___(JCR-1), Schedule 12

III. AVERAGE RATE BASE

Line	Item	2003 Total NSP	2003 N.D. Juris.	N. D. %
1	Plant in Service	773,831	70,355	9 1%
2	Accumulated Depreciation	327,766	30,164	9 2%
3	Net Plant in Service	446,065	40,191	9 0%
4	Plant Held for Future Use	0	0	*
5	Construct Work in Progress	7,429	822	11 1%
6	Materials and Supplies	2,071	189	9.1%
7	Fuel Stocks	28,155	2,937	10.4%
8	Prepayments & Other	7,263	750	10 3%
9	Customer Deposits	(322)	(113)	35 0%
10	Unamortized Expense	0	0	*
11	Cash Working Capital	0	0	*
12	Other Rate Base [1]	(6,792)	(558)	8 2%
13	Accum Deferred Taxes	(62,163)	(5,382)	8 7%
14	Total Other Rate Base	(24,359)	(1,355)	5 6%
15	Total Average Rate Base	421,706	38,836	9.2%

[1] Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, deferred gas costs, severance accrual, etc

Definition The incremental amount of gross revenue rquired to generate an additional dollar of operating income Gross earnings fees included

Let GR = Gross Revenue Conversion Factor
T= Federal and North Dakota Income Tax

Formula for Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - T}$$

Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - 0\ 3955}$$

GR = 1 65426

Direct Testimony and Schedules
Nicholas Paluck

Before the North Dakota Public Service Commission

In the Matter of Northern States Power Company
d/b/a Xcel Energy
Notice of Change in Rates
for Natural Gas Service

Case No. PU-400-04-578
Exhibit___

Class Cost of Service Study
and
Rate Design

December 1, 2004

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nicholas Paluck. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Principal Pricing Analyst of Gas Pricing employed by Xcel Energy Services Inc., the service company for the Xcel Energy Inc. holding company system.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCES.

A. Exhibit___(NNP-1), Schedule 1, is a resume of my education and professional background.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am presenting the Class Cost of Service Study ("CCOSS") for the Company's natural gas utility operations in North Dakota and providing rate-design proposals that will recover the revenue requirement provided by Mr. Jeffrey Robinson for the test year ending December 31, 2004. I also sponsor the proposed tariff sheets included in the Notice of Change in Rates for Natural Gas Service ("Notice") filed November 2, 2004.

II. CLASS COST OF SERVICE STUDY

Overview

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. The purpose of a CCOSS is to identify the revenues, costs, and profitability for each class of service.

Q. HOW IS A CLASS COST OF SERVICE STUDY PREPARED?

A. The CCOSS presented in this case is a fully distributed, embedded class cost of service study. In general, preparing a CCOSS involves the following four steps:

First, costs are identified by function and separated by jurisdiction. This step is shown in the testimony and exhibits of Mr. Jeffrey Robinson.

Second, costs (and revenues) that can be identified specifically by class are directly assigned to that class.

Third, all other costs are classified as customer, demand, or commodity-related and allocated to various customer classes using appropriate external or internal allocators.

The classification step helps identify the appropriate allocators and guides intra-class rate design. For instance, customer costs are costs that do not vary with usage or contributions to peak-day demand; rather, they vary with the number of customers. Ideally, all customer costs would be collected through a class-specific Basic Service Charge.

The allocation step determines the cost responsibility of each class. The goal in developing any allocator is to reflect accurately how and why a specific cost was incurred. For example, if a certain portion of the distribution system was designed and sized to meet the anticipated peak load on the system, then the cost of that system should be allocated to customer classes based on some measure of their contributions to system peak. Examples of external allocators are class contribution to design-day requirements, annual class sales, and the number of customers in the class. Other allocators may be developed internally within the CCOSS, as a result of mathematical operations and external allocations.

Fourth, the cost of serving each class is compared to the revenues it generates. This analysis yields the unit cost and revenue deficiency by major class of service (e.g., Residential) and subclass (e.g., with Space Heating).

Q. HAVE YOU PREPARED SUCH A CCOSS?

A. Yes. The CCOSS was included as Schedule 9 in the Xcel Energy's Notice filed with the Commission on November 2, 2004. In addition, Schedule 8 of the Notice summarizes the classification and allocation approaches used in the CCOSS. I incorporate those schedules as exhibits to my testimony.

Schedule 9 is an updated version of the CCOSS that has been included in previous Xcel Energy rate cases, with one significant modification. Specifically, the Company has revisited and modified its approach to classifying and allocating the costs of natural gas mains.

Classification and Allocation of Mains

Q. DESCRIBE HOW THE COMPANY HAS MODIFIED ITS CLASSIFICATION AND ALLOCATION OF GAS MAINS.

A. In its most recent North Dakota rate case, Xcel Energy used an "average and excess" method to allocate the costs of transmission plant, regulator stations and mains. The use of this allocator assumes that mains, transmission plant and regulator stations are designed to serve two different functions: to deliver gas to all customers all year and to meet the design-day requirements of firm customers. The costs of transmission plant, regulator stations and mains were accordingly split into two components. This split was based on the system load factor – the ratio of average use to design-day use.

The "average day" component was allocated to all classes based on their average daily test-year use (or annual sales / 365). This component was classified as a "base capacity" cost.

The excess or design-day component was allocated to each class based on the difference between the class's design-day use and its average daily use. Because interruptible customers are interrupted during a design day, there was no allocation of this second component to the interruptible customer classes. Because this component represents the cost of meeting design-day requirements, it was classified as a "seasonal capacity" cost.

In this proceeding the Company proposes to retain the same approach for transmission plant and regulator stations. However, the Company is proposing to modify its treatment of gas mains by imputing a minimum distribution system prior to applying the average and excess allocator.

Specifically, a minimum system is imputed to identify the percentage of the total cost of mains that should be classified as customer-related costs and allocated accordingly. The average and peak allocator is then applied to the remaining costs, as described above.

Q. WHY IS XCEL ENERGY PROPOSING THIS MODIFICATION?

A. The imputation of a minimum distribution system recognizes that all customers take at least a minimum level of service, and the costs of designing and installing a system capable of serving customers' minimum loading requirements are customer-related costs. The costs of such a minimum system should be classified and allocated accordingly.

Q. HAVE OTHER REGULATORY COMMISSIONS GENERALLY ACCEPTED THIS TREATMENT OF MAINS IN UTILITY CCOSS?

A. Yes. The method proposed is similar to that proposed by Montana-Dakota Utilities ("MDU") in its recent gas rate case (Case No. PU-399-04-97), and approved by the Commission in September 2004. Xcel Energy also imputes a minimum distribution system in the CCOSS used for its gas rate cases in Minnesota.

Q. HAVE YOU PREPARED SUCH A STUDY?

A. Yes, a summary of the minimum-system study is included as Exhibit___(NNP-1), Schedule 2.

CCOSS Summary

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. The results with respect to revenue deficiencies (or surpluses) by customer class, based on the requested test year revenue requirement supported by Mr. Robinson, are summarized below.

Customer Class	Revenue Deficiency ($000)	Percent Increase Indicated
Residential Firm	3,009	11.3%
Commercial Firm	-1,119	-3.6%
Small Interruptible	-291	-7.6%
Large Interruptible	-319	-4.4%
Total	1,280	1.9%

III. RATE DESIGN GOALS

Q. WHAT ARE THE COMPANY'S PRIMARY PRICING OBJECTIVES IN THE DESIGN OF NATURAL GAS RATES?

A. The primary gas rate design objectives are:

1) To collect total revenues sufficient to recover Xcel Energy's test year cost of service, including a reasonable return on investment;
2) To reflect the cost of providing service to each customer class, as supported by the CCOSS;
3) To encourage sound economic energy use;
4) To create rates that are easily understood and accepted by customers to the extent possible;
5) To moderate billing impacts and avoid any undue price discrimination; and

6) To provide flexibility in pricing and service conditions, which will allow Xcel Energy's natural gas service to be competitive with other energy sources.

IV. TEST YEAR REVENUES

Q. WHAT ARE THE TEST YEAR REVENUES AT PRESENT AND PROPOSED RATES?

A. The 2004 test year revenues at present and proposed rates for the Gas Utility-North Dakota jurisdiction are $71,607,000 and $72,887,000, respectively. The $1,280,000 difference between the two revenue levels is the revenue deficiency developed by Mr. Robinson. Present rates refer to the rates authorized in the Company's last gas rate case, Case No. PU-400-00-521. The proposed rates are designed to produce an increase in retail revenues of $1,275,000 and other miscellaneous revenues of $5,000. Test year budgeted sales and transportation service volumes are applied to both present and proposed rates to obtain these test year revenues.

V. XCEL ENERGY REGULATED SERVICES

Q. WHAT GENERAL CATEGORIES OF NATURAL GAS SERVICE DOES XCEL ENERGY PROVIDE TO ITS CUSTOMERS IN NORTH DAKOTA?

A. The Company provides sales service and transportation service. Sales service can be thought of as the more traditional "bundled" gas utility service offering, in that Xcel Energy both procures wholesale gas supplies for these customers and distributes and resells the gas to them. Transportation customers acquire their own gas supplies and pipeline transportation to Xcel

Energy's town border station(s). Xcel Energy then delivers the gas to the transportation customers through the Company's gas distribution system.

For both sales and transportation customers, the Company offers both firm or interruptible service. Firm service is typically not subject to curtailment (e.g., interruption), and is priced to include the costs of providing this reliability. Service to customers taking interruptible service can be curtailed as needed to maintain system reliability.

Q. PLEASE SUMMARIZE THE COMPANY'S SERVICES.

A. The Company's natural gas services are summarized in the following table:

Services
Firm Sales
Residential
Commercial and Industrial
Interruptible Sales
Small Interruptible
Large Interruptible
Transportation Service
Firm
Interruptible

With minor exceptions, the charges for Transportation Service are equal to the charges for the comparable firm or interruptible sales service exclusive of the Cost of Gas Component. So the Company is essentially indifferent to whether a customer purchases sales or transportation service.

VI. REVENUE REQUIREMENT APPORTIONMENT

Q. HOW DO YOU APPORTION THE PROPOSED REVENUE REQUIREMENT AMONG CUSTOMER CLASSES?

A. The CCOSS was the starting point for the apportionment of the retail revenue requirement among the rate classes. But I tempered the goal of setting rates at embedded costs with other goals, such as emphasizing market-based pricing for competitive services and limiting rate increases to any class to moderate levels. Consequently, I used the CCOSS as a guideline, not the final authority.

Specifically, I first determined the revenue responsibility for the interruptible classes based on the market prices of customers' typical competitive alternatives. I then apportioned the remaining revenue requirement among the firm classes. My goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts.

The resulting apportionment based on this approach is provided in Exhibit___(NNP-1), Schedule 3. The value-based approach to pricing interruptible service results in the recovery of 109.5 percent of this class's embedded cost of service. I discuss the specific procedure I used to develop interruptible prices later in my testimony.

Under my proposed apportionment, the firm classes would generate revenue very close to, but not equal to, their respective costs of service. I am proposing to eliminate approximately 40 percent of the current subsidy provided to Residential customers. This approach would move this class significantly closer to cost, while limiting the overall increase to a reasonable level.

VII. OVERALL CLASS IMPACTS

Q. PLEASE DESCRIBE SCHEDULES 4 AND 5 INCLUDED IN THE NOTICE OF CHANGE IN RATES.

A. Schedule 4 of the Notice contains the present and proposed rates and typical bill impacts by class. Schedule 5 summarizes the present and proposed revenues and contains the number of customers, sales, present and proposed gas rates, and the resulting revenues. This information is provided in summary for each class (Page 1), and for each rate component charged to each class (Pages 2 and 3). Page 4 of Schedule 5 compares the resulting revenues under the proposed rates with the class revenue requirements as determined by the CCOSS. Page 4 of Schedule 5 also shows the dollar impacts of the proposed rates and the percentage changes in the customer and Distribution Charges. My testimony supports both of these schedules.

VIII. RATE DESIGN

Overview

Q. HOW ARE XCEL ENERGY'S CURRENT TARIFFS STRUCTURED?

A. The Company's current tariffs for gas distribution services are primarily structured as two-part rates consisting of a monthly fixed charge (the Basic Service Charge) and a volumetric rate (the Distribution Charge) applied to a customer's use during the billing period. In addition, the Cost of Gas charge recovers the cost of wholesale natural gas supplies and upstream

transportation and storage services, which are recovered on a pass-through basis and subject to an annual true-up. The Company is not proposing any changes to the Cost of Gas Charge in this proceeding.

Q. DO YOU BELIEVE THIS RATE DESIGN IS STILL APPROPRIATE?

A. This two-part rate gas distribution rate structure can achieve the pricing goals I listed earlier, but the levels of the individual rate components need to be revised.

Q. WHY DO YOU RECOMMEND CHANGES TO THE RATE LEVELS?

A. The salient shortcoming of our current pricing is that we recover a significant percentage of fixed costs through volumetric charges instead of through the fixed monthly charge. This deficiency causes several problems.

First, high-use customers subsidize low-use customers. In other words, the recovery of fixed costs through volumetric rates results in intra-class subsidies.

Second, because use per customer is declining, particularly in the Residential class, Xcel Energy's financial condition is adversely affected, as we are unable to recover our fixed costs because sales do not recover rising costs. Once a gas main or service line is installed, it is too late -- and not cost effective -- to substitute a smaller pipe if usage declines. While customer growth has traditionally addressed increasing costs over time, the net revenues resulting from this growth in the number of customers cannot offset the impact of declining use per customer.

Third, the recovery of a disproportionately high percentage of fixed costs through volumetric rates can lead to bill instability for customers. In cold winters, the Company over-recovers its fixed distribution costs at the same time customers are most affected by higher than normal energy bills because of their increased consumption.

Mr. Kent Larson also addresses the impacts associated with the recovery of fixed costs through volumetric rates.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THIS PROBLEM?

A. The Company is proposing two primary remedies. The first is to institute monthly fixed Basic Service Charges that more closely reflect the customer-related costs imposed by the various classes. This initiative is a direct remedy for the Company's above-discussed current pricing problems. It is particularly important for classes for whom the current Basic Service Charge is well below cost.

The second remedy is an innovative regulatory initiative to partially "decouple" our recovery of distribution costs from customer use. I will discuss this mechanism in detail later in my testimony

As a package, these two initiatives would have a stabilizing effect on customer bills and better match the Company's cost recovery with our cost of providing service.

Basic Service Charge

Q. WHAT CHANGES ARE YOU PROPOSING TO THE BASIC SERVICE CHARGES?

A. I recommend raising the Basic Service Charges to, or at least closer to, the appropriate cost-based levels for each customer class. Exhibit___(NNP-1), Schedule 4, compares my proposed Basic Service Charge for each class with the customer-related costs imposed by that class.

Q. PLEASE EXPLAIN HOW HIGHER BASIC SERVICE CHARGES MIGHT HELP STABILIZE CUSTOMER BILLS?

A. Customers pay the same level of fixed charges every month. For customers paying two-part rates, the variability in their bills for distribution service is attributable almost entirely to the variations in their monthly or annual use (i.e., the billing units to which the Distribution Charge is applied). To the extent volumetric rates are artificially high, a given variation in use will result in a larger bill impact on a high use customer than if rates were set at the appropriate cost-based levels. Higher Basic Service Charges allow for lower Distribution Charges. As volumetric rates are reduced, any given change in monthly or annual use will have a smaller impact on the high use customer's total bill.

Q. IS BILL INSTABILITY AN IMPORTANT ISSUE TO CUSTOMERS?

A. Bill instability is a critical issue for services such as natural gas, where customer use fluctuates significantly with the weather. To the extent bill fluctuations reflect the true costs either avoided or incurred as use and/or price changes, then these variations may be a reasonable price to pay to ensure appropriate cost recovery and send proper price signals. But there is little reason to

exacerbate the hardship on customers attributable to bill fluctuations by setting Distribution Charges that far exceed cost-based levels.

Q. SINCE THE MAJORITY OF A SALES CUSTOMER'S BILL IS FOR THE COST OF THE NATURAL GAS, HOW IMPORTANT IS REDUCING BILL FLUCTUATIONS FOR DISTRIBUTION SERVICE?

A. It is true that the majority of a Residential customer's bill recovers the Company's cost of purchasing gas and arranging for its interstate transportation to the town border station. These commodity-related costs can vary widely on a monthly and annual basis, due to changes in market prices and customer use. To the extent customer bills fluctuate accordingly, then leveling out the bills for distribution service would address only the smaller of the two sources of bill instability.

Nonetheless, the stability afforded by a higher Basic Service Charge is still warranted. In fact, the initiatives proposed by the Company in this proceeding for its distribution services would complement nicely the Company's strategy for reducing instability in the cost of gas. For example, the Company currently reduces the bill instability related to its cost of gas through its commodity supply hedging (e.g., financial instrument) activities. Taken as a package, the customer bill volatility mitigation initiatives related to both the Company's cost of wholesale gas supply and its distribution services charges would provide significant benefits to customers.

Q. WHY ARE YOU RECOMMENDING A RESIDENTIAL BASIC SERVICE CHARGE THAT FALLS WELL SHORT OF THE CUSTOMER-RELATED COSTS IMPOSED BY THESE CUSTOMERS?

A. I am recommending a modest increase – from $5.50 to $8.50 – for two reasons.

First, adoption of the partial decoupling proposal (discussed later) would address many of the same problems caused by an insufficient Basic Service Charge.

Second, raising the monthly charge from $5.50 to the cost-based level of $17.99, while appropriate from a cost-causation perspective, would impose significant percentage bill increases on low-use customers. As stated earlier, one of the Company's pricing objectives is to moderate our rate increases. The $8.50 per month Basic Service Charge satisfies this objective.

Taken as a package, partial decoupling and a modest increase in the Residential class Basic Service Charge would strike a good balance between reducing the flaws in our current pricing and moderating the billing impacts on low-use customers.

Partial Decoupling

Q. PLEASE DESCRIBE THE "PARTIAL DECOUPLING" MECHANISM YOU PREVIOUSLY MENTIONED.

A. Xcel Energy proposes to separate the recovery of distribution costs from variations in weather-normalized use per customer. Specifically, the Company proposes to "true-up" residential customer bills to capture what natural gas

customers would have paid had their class's weather-normalized use not deviated from the volume established by the Commission in this proceeding.

Q. WHY DO YOU USE THE TERM "PARTIAL DECOUPLING" TO DESCRIBE THE COMPANY'S PROPOSAL?

A. Many factors contribute to variations in customer bills and the recovery of fixed distribution costs. Among these factors are weather, changes in the number of customers, and changes in use per customer. Regulatory mechanisms that adjust for all, or virtually all, of these factors can be viewed as "full decoupling" approaches. By focusing solely on weather-normalized use per customer, Xcel Energy is proposing to address only one of the primary contributors to the earnings erosion experienced by the North Dakota natural gas utility operation and discussed in more detail by Mr. Larson.

Q. WHY IS XCEL ENERGY FOCUSING ON ONLY ONE PARTICULAR SOURCE OF EARNINGS EROSION?

A. One of our most pressing concerns is the decline in use per customer. Rates are set based on projected use per customer during a test year. As this use declines, all else being equal, the approved rates no longer allow the Company to recover its fixed costs of providing gas distribution service. Consequently, Xcel Energy proposes to separate its recovery of distribution costs from variations in weather-normalized use per customer.

Q. ARE YOU RECOMMENDING THAT THE COMPANY'S REVENUE STREAM FROM EACH CLASS BE PROTECTED FROM CHANGES IN USE PER CUSTOMER?

A. No. While any decline in use per customer erodes the Company's recovery of fixed costs, the Company proposes to limit its partial decoupling proposal to the Residential class. This class is projected to account for about 40 percent of the test-year distribution revenues collected through volumetric Distribution rates.

Q. WHAT ARE THE ADVANTAGES OF THIS MORE LIMITED APPROACH?

A. Xcel Energy recognizes that it is suggesting an important and significant regulatory change. Several state commissions have approved various approaches to stabilizing customer bills and ensuring the recovery of fixed costs, including the North Dakota Commission. The Commission recently approved MDU's natural gas Delivery Distribution Stabilization Mechanism ("DDSM") in Case No. PU-399-04-97.

The Company's proposal is conservative in that it targets the most pressing source of cost recovery erosion (declining weather-normalized use per customer) and the customer class (Residential) for whom declining use poses a significant risk of inadequate cost recovery by the Company. This limited approach would be easier to implement and monitor, and provide valuable information if the Commission later decided to extend the decoupling mechanism to other sources of inadequate cost recovery and/or to other customer classes.

Q. WOULDN'T THE HIGHER BASIC SERVICE CHARGE YOU ARE PROPOSING ACCOMPLISH THE SAME OBJECTIVE AS PARTIAL DECOUPLING?

A. To a lesser degree, yes. But it would not address the problem caused by declining use per customer. More specifically, the Company would not be able to recover its costs of service absent some form of decoupling.

As I explained previously, the Company is proposing to recover only about 47 percent of the customer-related costs allocated to the Residential class through the monthly Basic Service Charge. The remaining customer-related costs, and all of the capacity-related costs imposed by the Residential class, would be recovered through the volumetric Distribution Charge. (By contrast, interstate gas pipelines recover 100 percent of their fixed costs in fixed monthly charges.) To the extent Residential use per customer declines, there would still be an inadequate recovery of costs from Residential customers in future years. Partial decoupling would mitigate this problem by eliminating the impact of changes in weather-normalized use per customer.

A higher monthly fixed Basic Service Charge and partial decoupling should be viewed as complementary initiatives. The former would reduce the fluctuations in the Company's cost recovery and customers' annual and monthly bills attributable to both weather and non-weather related fluctuations in use. The latter would provide a more complete remedy for the one source of earnings erosion (weather-normalized use per customer) of most concern to the Company in this proceeding.

This "partial decoupling" of revenues from sales volumes would also remove the primary financial disincentive to the Company from encouraging investments in customer conservation and energy efficiency.

Taken as a whole, the two initiatives would reduce intra-class subsidies, reduce fluctuations in customers' annual and monthly bills, stabilize the Company's cost recovery, and encourage Company efforts to further the important public-policy goal of energy efficiency. Moreover, these important goals would be advanced without imposing large bill impacts on any class or subset of customers.

Q. CAN YOU SUMMARIZE THE REGULATORY INITIATIVES IN OTHER STATES THAT ACCOMPLISH SIMILAR GOALS?

A. Yes. Exhibit___(NNP-1), Schedule 5, summarizes the mechanisms implemented in North Dakota and other states to address declining use per customer. They can be roughly divided into initiatives that rely on different approaches to setting sales volumes and rate-design initiatives. Two of the six rate-design initiatives listed in this exhibit are partial decoupling and higher Basic Service Charges – the same two options proposed by Xcel Energy in this proceeding.

This exhibit also illustrates that the Company's proposals in this proceeding are conservative, in that they do not represent a shift in regulatory policy as dramatic as remedies such as the "100% Fixed Rate" or "Full Revenue Decoupling" options like MDU's DDSM.

Moreover, Xcel Energy has recently proposed the same partial decoupling mechanism in Minnesota as part of its currently pending natural gas general rate case (MPUC Docket No. G002/GR-04-1511).

Q. YOU HAVE DESCRIBED CONCEPTUALLY THE PROPOSED DECOUPLING MECHANISM. HOW DO YOU PROPOSE TO IMPLEMENT IT?

A. Each month the Company would track Residential weather-normalized use per customer (in aggregate). These sales would be compared to the monthly residential use per customer approved by the Commission in this proceeding. This difference would then be multiplied by the test-year number of customers to yield the decoupling adjustment in terms of sales volumes. The over- or under-collection of revenues would be derived by multiplying these sales volumes by the Residential Distribution Charge.

These monthly over- and/or under-collections would be placed in a subaccount of Account 186 (Miscellaneous Deferred Debits). The balance in the subaccount at the end of each fiscal year would be divided by projected Residential throughput over the next calendar year to yield an Decoupling adjustment per therm. The adjustment would then be applied to all Residential customer volumetric use during that year.

An example of this derivation is provided in Exhibit___(NNP-1), Schedule 6.

Q. WHEN WOULD THE COMPANY INITIATE THIS MECHANISM?

A. Xcel Energy would track the variations in use per customer described above beginning with the first billing month after the Commission's Final Order in

this proceeding. The Company would compile the results for each fiscal year ending June 30 and file its proposed surcharge or credit with the NDPSC

Q. WOULD THE INITIAL ADJUSTMENT BE LIMITED TO A PARTIAL YEAR?

A. The initial adjustment would cover the fiscal period from July 1, 2005, through June 30, 2006, and go into effect on September 1, 2006. Each subsequent annual adjustment would reflect the results from a full 12 months. within two months, or by September 1. This bill adjustment would become effective on the filing date and remain in effect for the next 12 months, or until September 1 of the subsequent year. At that point the next year's adjustment would be substituted.

Q. WHY DO YOU PROPOSE A FISCAL YEAR ENDING JUNE 30 FOR DERIVING THE ANNUAL WEATHER-NORMALIZED USE PER CUSTOMER?

A. This timeline dovetails with that already approved for the annual true-up of purchased gas costs. By filing and implementing the gas-cost and decoupling adjustments on the same dates, the Company would minimize its administrative costs and promote regulatory efficiency.

Q. SINCE ACTUAL CUSTOMER USE DURING THE FOLLOWING YEAR WILL ALMOST CERTAINLY BE DIFFERENT THAN PROJECTED, HOW DO YOU PROPOSE TO TREAT THE INEVITABLE OVER OR UNDER RECOVERIES?

A. The over or under recovery in each year would be rolled into the following year's decoupling adjustment factor. This approach is similar to that used to reconcile gas costs with gas-cost recovery. Exhibit___(NNP-1), Schedule 6, illustrates how this true-up would be derived.

Q. WOULD CARRYING CHARGES BE INCLUDED IN THE DERIVATION OF THE ADJUSTMENT FACTOR?

A. Yes. Each year's revenue adjustment would be escalated for one year at the Company's before-tax cost of capital. Again, the illustrative derivation provided in Exhibit___(NNP-1), Schedule 6, demonstrates how these carrying costs would be applied.

Q. WHAT NORMALIZATION PROCEDURE WOULD BE USED TO DERIVE THE MONTHLY WEATHER-NORMALIZED USE PER CUSTOMER?

A. The Company would use the weather-normalization procedure approved by the Commission to derive test-year sales volumes in this proceeding.

Q. ARE YOU INCLUDING A PROPOSED TARIFF THAT IMPLEMENTS THIS LIMITED DECOUPLING PROPOSAL?

A. Yes. A proposed rider governing the conditions and implementation of the proposal was included in Schedule 2, page 5, of the Notice.

IX. OTHER RATE-DESIGN PROPOSALS

Residential

Q. WHAT CHANGE IS XCEL ENERGY PROPOSING TO THE RESIDENTIAL BASIC SERVICE CHARGE?

A. For the reasons previously explained, Xcel Energy is proposing to increase the monthly Basic Service Charge from $5.50 to $8.50.

Q. WHAT DISTRIBUTION CHARGE IS PROPOSED FOR THE RESIDENTIAL CLASS?

A. Xcel Energy is proposing a slight decrease in the Distribution Charge from $0.12480 to $0.12388 per therm. A comparison of bills for various usage levels under present and proposed rates is shown on Schedule 4 of the Notice.

Q. EXPRESSED AS A PERCENTAGE OF DISTRIBUTION (I.E., NON-GAS) SERVICE RATES, THE RESIDENTIAL INCREASE IS SIGNIFICANTLY HIGHER THAN THE 4.6 PERCENT SHOWN ON SCHEDULE 4 OF THE NOTICE. IN LIGHT OF THAT, WHY IS THE PROPOSED INCREASE TO THE RESIDENTIAL CLASS REASONABLE?

A. Our proposal is reasonable for two primary reasons. First, the current Residential rates provide revenue significantly below the class cost of service. The proposed increase eliminates only about one third of the shortfall. Second, because the overall increase is relatively small, this is an appropriate time to impose a larger portion of the needed overall rate increase on the Residential class.

Commercial Firm Service

Q. WHAT CHANGES ARE YOU PROPOSING TO THE FIRM COMMERCIAL AND INDUSTRIAL RATES?

A. The Company is proposing to increase the Commercial and Industrial Basic Service Charge from $14.00 to $20.00. This increase is justified by the cost-of-service study. To achieve the same overall revenues from this class, the per-therm Distribution Charge is decreased from $0.11280 to $0.10120.

Interruptible Sales Service

Q. ON WHAT CRITERIA DID YOU RELY TO DESIGN THE COMPANY'S PROPOSED INTERRUPTIBLE RATES?

A. The primary criteria are as follows:

- Interruptible rates should reflect the anticipated value of service to the customer. This goal was accomplished by pricing Interruptible service at a rate competitive with the cost of alternate fuels available to these customers. The upper limit used for the Interruptible sales service commodity pricing was the price of No. 2 fuel oil, since most of these customers use No. 2 fuel oil as their primary alternate fuel.
- Interruptible prices should reflect a reasonable discount from firm prices, because interruptible service is of less value. If No. 2 fuel oil is priced higher than firm gas service, then the corresponding firm rates, less a reasonable discount to reflect the lower reliability of interruptible service, become the upper limits for Interruptible rates.
- Interruptible customers should not be subsidized by other classes of service. Interruptible rates should recover at least the Company's cost of gas plus variable operating and maintenance expenses, and make a reasonable contribution to fixed cost recovery.

Q. HOW WERE THE INTERRUPTIBLE RATES DEVELOPED BASED ON THESE CRITERIA?

A. The current Basic Service Charges for Small and Large Interruptible Service slightly exceed their cost-based levels. Consequently, I propose no increase in these charges.

The proposed Distribution Charges for the Large Interruptible Service were designed to generate less than a 1 percent overall increase for the class. This small increase would maintain a reasonable differential between the rates for this natural gas service and the cost of alternative fuels.

The Distribution Charge for the Small Interruptible class was increased from $0.07310 to $0.07740 per therm to maintain a reasonable differential between the rates for this service and the cost of alternative fuels.

The various components of the Interruptible rates are identified in Schedule 5, Page 3, of the Notice.

Q. HAS XCEL ENERGY RETAINED THE FLEXIBLE PRICING PROVISIONS FOR ITS INTERRUPTIBLE SALES TARIFFS?

A. Yes. The Company proposes to retain the rate flexibility currently authorized in North Dakota. The ceiling of the proposed range is the applicable fixed rate explained above. The floor has been set at the variable O&M cost as determined in the CCOSS.

Q. WILL THE PROPOSED INTERRUPTIBLE RATES RECOVER MORE THAN THE COSTS IMPOSED BY THESE CLASSES?

A. Yes. The proposed Interruptible rates would recover about $667,000 above the embedded costs imposed by the interruptible classes, thereby reducing the residual costs that must be recovered from firm customer classes.

Firm and Interruptible Transportation Service

Q. WHAT CHANGES ARE YOU PROPOSING TO THE TRANSPORTATION RATES?

A. In Xcel Energy's rate design, transportation rates are the same as the corresponding sales rates, except that transportation customers pay a Basic Service Charge that is $25 higher to reflect the additional customer-related costs of serving such customers and no Cost of Gas charge. This approach ensures that Xcel Energy will be indifferent as to what method of procuring gas the customer chooses (i.e., Xcel Energy sales gas or gas purchased directly from a marketer). Therefore, my explanation of the proposed Basic Service Charges and Distribution Charges for sales customers also holds for the corresponding transportation rates.

X. ALTERNATIVE RATE DESIGN PROPOSAL TO MANAGE VOLATILITY

Q. YOU HAVE DISCUSSED XCEL ENERGY'S PROPOSAL TO MANAGE VOLATILITY THROUGH PARTIAL DECOUPLING. IS THERE AN ALTERNATIVE APPROACH?

A. Yes. An alternative approach to managing volatility and allowing the Company a reasonable opportunity to earn its authorized return is to substitute a significantly higher Residential class Basic Service Charge for partial decoupling. A higher Basic Service Charge would mitigate revenue declines due to reductions in sales volumes, thus offering protection similar to that afforded by rate decoupling, while at the same time providing some bill stability for customers.

Q. WHAT INCREASE WOULD YOU RECOMMEND UNDER YOUR ALTERNATIVE PROPOSAL?

A. I would raise the monthly charge to $14.00, which represents an increase of $8.50. The Residential Distribution Charge would be lowered to $0.04833/therm to recover the same revenues from the Residential class as shown in Exhibit___(NNP-1), Schedule 3. In other words, the revenue apportionment would be the same under the preferred (partial decoupling) and alternative (higher Residential class Basic Service Charge) approaches.

Q. WHY WOULD YOU SET THE BASIC SERVICE CHARGE AT $14.00?

A. Based on the CCOSS, the test-year monthly customer-related cost imposed by Residential customers is about $17.99 per month. The current charge of $5.50 is approximately 30 percent of this appropriate cost-based level. Increasing the charge to $14.00 would remove over one-half of the under-recovery of customer costs attributable to our current residential Basic Service Charge rates.

Q. HOW WOULD HIGHER BASIC SERVICE CHARGES MITIGATE CONCERNS RELATED TO DECLINING USE PER CUSTOMER?

A. As I stated earlier, most of the Company's distribution costs are essentially fixed in nature (e.g., once a pipe is installed it is too late to substitute a smaller pipe if usage declines). If a utility recovers fixed costs though volumetric rates, then the utility can recover these costs only if usage remains the same as that approved in the most recent test year. But the assumption of stable use per customer is no longer valid. While customer growth has traditionally addressed increasing costs over time, the net revenues resulting from this growth cannot offset the impact of declining use per customer. Raising the Residential Basic Service Charge to $14 would reduce the percentage of fixed

costs collected through the volumetric rates, thereby reducing – but not eliminating – the effect on Company earnings declining use per customer.

Q. WHY WOULDN'T YOU ELIMINATE THE EARNINGS IMPACT OF DECLINING USE PER CUSTOMER BY SETTING BASIC SERVICE CHARGES AT HIGHER LEVELS?

A. There are two reasons. First, under my alternative proposal only about 78 percent of the customer-related costs imposed by the Residential class would be collected through a fixed Basic Service Charge. Second, the utility's fixed costs can be classified as either capacity- or customer-related costs. Even if we increased Basic Service Charges to their appropriate cost-based levels, the recovery of fixed capacity-related costs would still be at risk because Residential use per customer is declining. Thus, my alternative proposal addresses only a portion of the earnings erosion attributable to volumetric charges that recover fixed costs. The partial decoupling proposal would be more effective in that regard.

Q. HOW WOULD A $14.00 CHARGE BENEFIT CUSTOMERS?

A. As I mention previously, an under-priced Basic Service Charge results in intra-class subsidies and increasing the volatility of monthly and annual bills. A charge of $14.00 would reduce these effects of the current Basic Service Charge rates.

Q. COULD YOU ELABORATE ON HOW A MORE COST-BASED BASIC SERVICE CHARGE WOULD REDUCE INTRA-CLASS SUBSIDIES?

A. Yes. Currently, a large percentage of our fixed costs is collected through volumetric charges, as discussed earlier. However, rates within a class are effectively calculated on average use. Consequently, a high-use customer

contributes much more to the recovery of fixed costs than a low-use customer, even though the two customers impose similar levels of fixed costs. The result is intra-class subsidies.

Q. HAVE YOU CALCULATED THE BILLING IMPACTS OF THE $14.00 CHARGE?

A. Yes. Schedule 4 of the Notice includes billing impacts at various levels of monthly use. The percentage impacts vary greatly. A typical non space-heating residential customer using 10 therms per month would receive an increase of about 57 percent, while a residential customer with relatively high usage of 125 therms per month would experience a bill decrease of about 1 percent.

When evaluating these billing impacts, it is important to remember that the large percentage increases to low-use customers represent relatively small dollar amounts. For example, the 57 percent increase noted above translates into a monthly impact of $7.74. This level of fixed monthly cost increase is not out of line with similar increases in other utility services over the past few years such as basic local telephone service, cable television, etc.

XI. OTHER TARIFF CHANGES

Overview

Q. IS XCEL ENERGY PROPOSING ANY OTHER TARIFF CHANGES?

A. Yes. Xcel Energy is proposing a number of changes to the "Rate Schedules" section (Section 5), and the "General Rules and Regulations" section (Section 6) of its tariff book. Schedule 2 of the Notice contains the proposed tariffs.

Schedule 3 of the Notice contains a redline version of the proposed tariffs. These changes will be discussed by section below.

Section 5 Tariff Changes

Q. ARE YOU PROPOSING TO ELIMINATE ANY EXISTING SERVICES?

A. Yes. The Company is proposing to eliminate two services: the Gas Yard Lighting Service (currently closed) and the Standby Service Rider.

Q. WHY ARE YOU PROPOSING TO ELIMINATE GAS YARD LIGHTING SERVICE AND THE STANDBY SERVICE RIDER?

A. No customers are currently taking either of these services; consequently, the Company believes these services are no longer necessary and the tariff sheet should be removed from the North Dakota Gas Rate Book.

Q. HAVE YOU PROPOSED ANY CHANGES TO THE TRANSPORTATION TARIFFS?

A. Yes. The Company is proposing two changes. The first is to increase the limit of Intra-day 1 nominations from 8 to 16 hours of prorated flow. The second proposal is to update the undertake/overtake cashout calculation to minimize "gaming" when purchased-gas prices fluctuate. Such gaming could potentially inflict higher costs on bundled sales service customers.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO LIMITED FIRM SERVICE?

A. Yes, the Company is proposing a change to the method of allocating the cost of propane used to provide Limited Firm Service to provide pricing that more appropriately reflects the cost of the supplies used to provide the service.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO SECTION 5 OF THE TARIFF?

A. The Company proposes other minor language changes throughout sections 5 and 6 to clarify various tariff provisions. These text changes are all identified in the redline version of the tariffs, (Schedule 3 of the Notice), by a "T" in the margin.

Section 6 Tariff Changes

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CHANGES TO SECTION 6 OF THE TARIFF.

A. Xcel Energy is proposing the following changes to section 6:

1) A refinement of the methodology for calculating winter construction charges,
2) An increase in the returned check charge, and
3) A refinement of the Main and Service Extension Policy.

I will address these issues in the order presented.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO WINTER CONSTRUCTION CHARGES.

A. The Company currently receives a fixed fee of $100 for each Winter Construction service extension project, plus $3.00 per foot of service installed. The current charge for Main extensions is $3.00 per foot. The current winter construction charges constitute a "bundled" charge that primarily covers the cost of thawing the ground and excavating the trench where the new service pipe will attach to the main.

The Company is proposing to unbundle the charge in order to more accurately recover the specific costs incurred for winter construction. The Company's proposed fee includes two variable components. First, the

Company proposes to charge for each excavation unit (specialized piece of equipment such as a frost burner or frost wheel) the job requires, at $400 per unit. Second, customers would pay $3.00 for each foot of service pipe; the $100 fixed fee would be removed.

Q. WHAT IS THE COMPANY'S REASONING FOR PROPOSING THESE CHANGES?

A. This method more accurately reflects the Company's incremental cost related to Winter Construction, in that the most significant incremental cost is the cost of the frost burners needed to thaw the ground prior to excavation. Consequently, the proposed charges would more accurately collect costs on a per-job basis.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RETURNED CHECK CHARGES?

A. Xcel Energy is proposing to increase this charge from $5 to $15.

Q. WHAT IS THE BASIS FOR THIS INCREASE?

A. The financial institutions that provide this service to the Company have increased their charges. The proposed increase merely reflects this change in the external environment, as well as the Company's own labor costs for processing returned checks.

Q. WHAT WILL THE FINANCIAL IMPACT OF THIS CHANGE BE ON THE COMPANY'S OTHER REVENUES?

A. The North Dakota gas utility operation experiences about 339 returned checks per year. A $10 increase per check would generate an extra $3,390. This increase in proposed revenues is included in Other Revenues on Schedule 5 of

the Notice. So the anticipate revenue increase from this charge is included as a revenue credit to other rates. The additional revenue does not increase the Company's earnings.

Q. WHAT REFINEMENTS DOES THE COMPANY PROPOSE TO ITS MAIN AND SERVICES EXTENSION POLICY?

A. The Company proposes to determine the cost a customer may need to contribute to an extension based on the Company's "current cost," and eliminate the specific per-foot charges for different sizes of pipe. The "current cost" would be the average pipe cost per foot, as determined from the most recently available annual cost data. This change would allow the Company to analyze current projects based on more recent costs.

Q. IS THE COMPANY PROPOSING CHANGES TO OTHER SECTIONS OF THE TARIFF BOOK?

A. Yes. The Company proposes to revise the Table of Contents (Section 1) and Technical and Special Terms Section (Section 4) to reflect rate additions and deletions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company d/b/a Xcel Energy - Notice of Change in Rates For Natural Gas Service	))))	Case No. PU-400-04-578

AFFIDAVIT OF
Nicholas N. Paluck

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Nicholas N. Paluck

Subscribed and sworn to before me, this 1 day of Dec., 2004.

Barbara J. Bridgeman
Notary Public

BARBARA J BRIDGEMAN
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES 1-31-2005

Nicholas N. Paluck
Principal Pricing Analyst, Xcel Energy Services, Inc.
414 Nicollet Mall, Minneapolis, MN 55401

CURRENT RESPONSIBILITIES

Responsible for monthly Cost of Gas and annual Cost of Gas True-up filings, gas utility revenue budgeting for Northern States Power Company (MN). Responsible for coordination and implementation of various compliance and miscellaneous natural gas filings.

PREVIOUS EMPLOYMENT

Principal & Sr. Pricing Analyst	Xcel Energy Services, Inc.	2000-present
Gas Supply Analyst	Northern States Power Co.	1998-2000
Staff Economist	Christensen Associates	1997-1998

EDUCATION

- Master of Business Administration (Finance), University of Minnesota, 2004
- Bachelor of Arts, Economics, University of Minnesota – Morris, 1997

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
1,132	3,509	Fargo-ND-Gas	1961	Main Gas Steel 2 Inch and Under	3 1
201,493	564,180	Fargo-ND-Gas	1962	Main Gas Steel 2 Inch and Under	2 8
13,541	38,457	Fargo-ND-Gas	1963	Main Gas Steel 2 Inch and Under	2 840025847
9,920	26,784	Fargo-ND-Gas	1964	Main Gas Steel 2 Inch and Under	2 7
44	95	Fargo-ND-Gas	1964	Main Gas Steel 2 Inch and Under	2 15
702	1,650	Fargo-ND-Gas	1965	Main Gas Steel 2 Inch and Under	2 35
14,774	42,845	Fargo-ND-Gas	1965	Main Gas Steel 2 Inch and Under	2 9
2,404	4,927	Fargo-ND-Gas	1965	Main Gas Steel 2 Inch and Under	2 049696339
452	858	Fargo-ND-Gas	1966	Main Gas Steel 2 Inch and Under	1 899026549
10,315	27,335	Fargo-ND-Gas	1966	Main Gas Steel 2 Inch and Under	2 65
2,157	4,143	Fargo-ND-Gas	1967	Main Gas Steel 2 Inch and Under	1 920690774
424	920	Fargo-ND-Gas	1967	Main Gas Steel 2 Inch and Under	2 17
12,008	32,662	Fargo-ND-Gas	1967	Main Gas Steel 2 Inch and Under	2 72
8,641	17,098	Fargo-ND-Gas	1968	Main Gas Steel 2 Inch and Under	1 97870964
2,240	3,066	Fargo-ND-Gas	1968	Main Gas Steel 2 Inch and Under	1 368803571
278	436	Fargo-ND-Gas	1968	Main Gas Steel 2 Inch and Under	1 568633094
555	1,804	Fargo-ND-Gas	1969	Main Gas Steel 2 Inch and Under	3 25
1,411	5,686	Fargo-ND-Gas	1969	Main Gas Steel 2 Inch and Under	4 03
1,327	9,289	Fargo-ND-Gas	1970	Main Gas Steel 2 Inch and Under	7
76	423	Fargo-ND-Gas	1970	Main Gas Steel 2 Inch and Under	5 57
840	4,284	Fargo-ND-Gas	1970	Main Gas Steel 2 Inch and Under	5 100095238
1,106	4,943	Fargo-ND-Gas	1971	Main Gas Steel 2 Inch and Under	4 469520796
465	2,544	Fargo-ND-Gas	1971	Main Gas Steel 2 Inch and Under	5 47
815	3,050	Fargo-ND-Gas	1972	Main Gas Steel 2 Inch and Under	3 742613497
300	306	Fargo-ND-Gas	1973	Main Gas Steel 2 Inch and Under	1 02
104	101	Fargo-ND-Gas	1973	Main Gas Steel 2 Inch and Under	0 97
1,652	2,280	Fargo-ND-Gas	1973	Main Gas Steel 2 Inch and Under	1 380024213
448	5,712	Fargo-ND-Gas	1974	Main Gas Steel 2 Inch and Under	12 75033482
119	1,453	Fargo-ND-Gas	1975	Main Gas Steel 2 Inch and Under	12 21
860	12,576	Fargo-ND-Gas	1975	Main Gas Steel 2 Inch and Under	14 62380233
90	801	Fargo-ND-Gas	1976	Main Gas Steel 2 Inch and Under	8 902222222
203	18,906	Fargo-ND-Gas	1979	Main Gas Steel 2 Inch and Under	93 13270936
20	203	Fargo-ND-Gas	1980	Main Gas Steel 2 Inch and Under	10 1355
310	37,685	Fargo-ND-Gas	1986	Main Gas Steel 2 Inch and Under	121 5629355
166	13,088	Fargo-ND-Gas	1994	Main Gas Steel 2 Inch and Under	78 84421687
30	1,064	Fargo-ND-Gas	1995	Main Gas Steel 2 Inch and Under	35 47166667
159	13,485	Fargo-ND-Gas	1996	Main Gas Steel 2 Inch and Under	84 81132075
3	1,930	Fargo-ND-Gas	1997	Main Gas Steel 2 Inch and Under	643 3766667
272	11,564	Fargo-ND-Gas	1998	Main Gas Steel 2 Inch and Under	42 51591912
480	38,176	Fargo-ND-Gas	2000	Main Gas Steel 2 Inch and Under	79 53391667
518	5,066	Fargo-ND-Gas	1958	Main Gas Steel Over 2 Inch to 4 Inch	9 78
3,315	17,603	Fargo-ND-Gas	1960	Main Gas Steel Over 2 Inch to 4 Inch	5 31
10,118	53,625	Fargo-ND-Gas	1961	Main Gas Steel Over 2 Inch to 4 Inch	5 3
21,444	85,990	Fargo-ND-Gas	1962	Main Gas Steel Over 2 Inch to 4 Inch	4 01
66,771	328,545	Fargo-ND-Gas	1962	Main Gas Steel Over 2 Inch to 4 Inch	4 920471911
6,040	24,341	Fargo-ND-Gas	1963	Main Gas Steel Over 2 Inch to 4 Inch	4 03
7,645	37,002	Fargo-ND-Gas	1963	Main Gas Steel Over 2 Inch to 4 Inch	4 84
4,332	21,097	Fargo-ND-Gas	1964	Main Gas Steel Over 2 Inch to 4 Inch	4 87
1,407	5,459	Fargo-ND-Gas	1964	Main Gas Steel Over 2 Inch to 4 Inch	3 88
7,088	36,503	Fargo-ND-Gas	1965	Main Gas Steel Over 2 Inch to 4 Inch	5 15
3,089	12,850	Fargo-ND-Gas	1965	Main Gas Steel Over 2 Inch to 4 Inch	4 16
2,746	10,270	Fargo-ND-Gas	1966	Main Gas Steel Over 2 Inch to 4 Inch	3 74
2,353	10,777	Fargo-ND-Gas	1966	Main Gas Steel Over 2 Inch to 4 Inch	4 58
772	3,003	Fargo-ND-Gas	1967	Main Gas Steel Over 2 Inch to 4 Inch	3 89
6,123	29,513	Fargo-ND-Gas	1967	Main Gas Steel Over 2 Inch to 4 Inch	4 82
977	2,811	Fargo-ND-Gas	1968	Main Gas Steel Over 2 Inch to 4 Inch	2 877492323
11,935	43,644	Fargo-ND-Gas	1968	Main Gas Steel Over 2 Inch to 4 Inch	3 656811898
585	3,352	Fargo-ND-Gas	1969	Main Gas Steel Over 2 Inch to 4 Inch	5 730273504
662	4,601	Fargo-ND-Gas	1969	Main Gas Steel Over 2 Inch to 4 Inch	6 95
316	3,722	Fargo-ND-Gas	1970	Main Gas Steel Over 2 Inch to 4 Inch	11 78
3,447	33,953	Fargo-ND-Gas	1970	Main Gas Steel Over 2 Inch to 4 Inch	9 85
756	6,555	Fargo-ND-Gas	1971	Main Gas Steel Over 2 Inch to 4 Inch	8 67
1,326	9,998	Fargo-ND-Gas	1971	Main Gas Steel Over 2 Inch to 4 Inch	7 54
3,034	23,619	Fargo-ND-Gas	1972	Main Gas Steel Over 2 Inch to 4 Inch	7 784617666
779	5,077	Fargo-ND-Gas	1972	Main Gas Steel Over 2 Inch to 4 Inch	6 517124519
168	924	Fargo-ND-Gas	1973	Main Gas Steel Over 2 Inch to 4 Inch	5 502261905
549	1,213	Fargo-ND-Gas	1973	Main Gas Steel Over 2 Inch to 4 Inch	2 21
1,038	20,625	Fargo-ND-Gas	1975	Main Gas Steel Over 2 Inch to 4 Inch	19 87
210	3,243	Fargo-ND-Gas	1976	Main Gas Steel Over 2 Inch to 4 Inch	15 44157143
88	3,736	Fargo-ND-Gas	1979	Main Gas Steel Over 2 Inch to 4 Inch	42 45159091
20	381	Fargo-ND-Gas	1980	Main Gas Steel Over 2 Inch to 4 Inch	19 041
86	21,411	Fargo-ND-Gas	1984	Main Gas Steel Over 2 Inch to 4 Inch	248 9609302
0	10	Fargo-ND-Gas	1991	Main Gas Steel Over 2 Inch to 4 Inch	98000
479	27,249	Fargo-ND-Gas	1994	Main Gas Steel Over 2 Inch to 4 Inch	56 8876618
265	25,216	Fargo-ND-Gas	1998	Main Gas Steel Over 2 Inch to 4 Inch	95 154
267	14,616	Fargo-ND-Gas	1999	Main Gas Steel Over 2 Inch to 4 Inch	54 74153558
(1,635)	-10,304	Fargo-ND-Gas	1961	Main Gas Steel Over 4 Inch to 8 Inch	6 302097859

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
17,512	157,958	Fargo-ND-Gas	1961	Main Gas Steel Over 4 Inch to 8 Inch	9 02
30,435	206,654	Fargo-ND-Gas	1962	Main Gas Steel Over 4 Inch to 8 Inch	6 79
8,440	71,993	Fargo-ND-Gas	1962	Main Gas Steel Over 4 Inch to 8 Inch	8 53
304	1,982	Fargo-ND-Gas	1963	Main Gas Steel Over 4 Inch to 8 Inch	6 52
566	4,670	Fargo-ND-Gas	1963	Main Gas Steel Over 4 Inch to 8 Inch	8 25
667	5,636	Fargo-ND-Gas	1964	Main Gas Steel Over 4 Inch to 8 Inch	8 45
833	5,406	Fargo-ND-Gas	1965	Main Gas Steel Over 4 Inch to 8 Inch	6 49
3,373	29,919	Fargo-ND-Gas	1965	Main Gas Steel Over 4 Inch to 8 Inch	8 87
893	6,894	Fargo-ND-Gas	1966	Main Gas Steel Over 4 Inch to 8 Inch	7 72
1,048	5,963	Fargo-ND-Gas	1966	Main Gas Steel Over 4 Inch to 8 Inch	5 69
1,286	10,648	Fargo-ND-Gas	1967	Main Gas Steel Over 4 Inch to 8 Inch	8 28
1,210	7,333	Fargo-ND-Gas	1967	Main Gas Steel Over 4 Inch to 8 Inch	6 06
1,085	7,014	Fargo-ND-Gas	1968	Main Gas Steel Over 4 Inch to 8 Inch	6 464368664
35,551	167,295	Fargo-ND-Gas	1968	Main Gas Steel Over 4 Inch to 8 Inch	4 705770302
379	3,252	Fargo-ND-Gas	1969	Main Gas Steel Over 4 Inch to 8 Inch	8 58
9,047	86,220	Fargo-ND-Gas	1972	Main Gas Steel Over 4 Inch to 8 Inch	9 530215541
119	3,953	Fargo-ND-Gas	1974	Main Gas Steel Over 4 Inch to 8 Inch	33 22
97	2,529	Fargo-ND-Gas	1976	Main Gas Steel Over 4 Inch to 8 Inch	26 0728866
537	10,301	Fargo-ND-Gas	1976	Main Gas Steel Over 4 Inch to 8 Inch	19 18167598
1	740	Fargo-ND-Gas	1978	Main Gas Steel Over 4 Inch to 8 Inch	740 1
2,027	66,343	Fargo-ND-Gas	1980	Main Gas Steel Over 4 Inch to 8 Inch	32 72970893
20	479	Fargo-ND-Gas	1980	Main Gas Steel Over 4 Inch to 8 Inch	23 962
708	89,413	Fargo-ND-Gas	1982	Main Gas Steel Over 4 Inch to 8 Inch	126 2892655
50	1,182	Fargo-ND-Gas	1990	Main Gas Steel Over 4 Inch to 8 Inch	23 6438
1,342	30,228	Fargo-ND-Gas	1990	Main Gas Steel Over 4 Inch to 8 Inch	22 5242623
149	52,173	Fargo-ND-Gas	1991	Main Gas Steel Over 4 Inch to 8 Inch	350 1555034
699	16,889	Fargo-ND-Gas	1991	Main Gas Steel Over 4 Inch to 8 Inch	24 16105866
20	393	Fargo-ND-Gas	1993	Main Gas Steel Over 4 Inch to 8 Inch	19 626
9,301	330,788	Fargo-ND-Gas	1993	Main Gas Steel Over 4 Inch to 8 Inch	35 56482206
5,364	409,055	Fargo-ND-Gas	1994	Main Gas Steel Over 4 Inch to 8 Inch	76 25935496
1,054	39,150	Fargo-ND-Gas	1995	Main Gas Steel Over 4 Inch to 8 Inch	37 14425996
5,705	232,651	Fargo-ND-Gas	1995	Main Gas Steel Over 4 Inch to 8 Inch	40 78019632
555	19,987	Fargo-ND-Gas	1996	Main Gas Steel Over 4 Inch to 8 Inch	36 01327928
13	5,783	Fargo-ND-Gas	1996	Main Gas Steel Over 4 Inch to 8 Inch	444 8392308
10,719	255,293	Fargo-ND-Gas	1997	Main Gas Steel Over 4 Inch to 8 Inch	23 81687471
382	7,069	Fargo-ND-Gas	1997	Main Gas Steel Over 4 Inch to 8 Inch	18 50586387
25	1,749	Fargo-ND-Gas	1998	Main Gas Steel Over 4 Inch to 8 Inch	69 9424
8,631	216,322	Fargo-ND-Gas	1998	Main Gas Steel Over 4 Inch to 8 Inch	25 06336577
134	5,769	Fargo-ND-Gas	1999	Main Gas Steel Over 4 Inch to 8 Inch	43 05208955
3,756	160,004	Fargo-ND-Gas	1999	Main Gas Steel Over 4 Inch to 8 Inch	42 59969915
4	37	Fargo-ND-Gas	1964	Main Gas Steel Over 8 Inch to 10 Inch	9 19
2,616	34,610	Fargo-ND-Gas	1957	Main Gas Steel Over 10 Inch to 12 Inch	13 23
1,317	16,963	Fargo-ND-Gas	1961	Main Gas Steel Over 10 Inch to 12 Inch	12 88
2,522	30,642	Fargo-ND-Gas	1962	Main Gas Steel Over 10 Inch to 12 Inch	12 15
4,423	51,130	Fargo-ND-Gas	1963	Main Gas Steel Over 10 Inch to 12 Inch	11 56
109	1,355	Fargo-ND-Gas	1964	Main Gas Steel Over 10 Inch to 12 Inch	12 43
3,030	39,481	Fargo-ND-Gas	1965	Main Gas Steel Over 10 Inch to 12 Inch	13 03
532	5,980	Fargo-ND-Gas	1966	Main Gas Steel Over 10 Inch to 12 Inch	11 24
520	6,313	Fargo-ND-Gas	1967	Main Gas Steel Over 10 Inch to 12 Inch	12 14
169	6,417	Fargo-ND-Gas	1976	Main Gas Steel Over 10 Inch to 12 Inch	37 97147929
350	19,820	Fargo-ND-Gas	1998	Main Gas Steel Over 10 Inch to 12 Inch	56 62805714
9,740	165,677	Fargo-ND-Gas	1961	Main Gas Steel Over 12 Inch to 20 Inch	17 01
4,319	87,330	Fargo-ND-Gas	1961	Main Gas Steel Over 12 Inch to 20 Inch	20 22
3,070	50,778	Fargo-ND-Gas	1962	Main Gas Steel Over 12 Inch to 20 Inch	16 54
5	2,847	Fargo-ND-Gas	2001	Main Gas Steel 2 Inch and Under	569 314
375	8,342	Fargo-ND-Gas	2001	Main Gas Steel Over 2 Inch to 4 Inch	22 24442667
25,191	1,401,800	Fargo-ND-Gas	2002	Main Gas Steel Over 4 Inch to 8 Inch	55 64687587
16	1,344	Fargo-ND-Gas	2002	Main Gas Steel 2 Inch and Under	83 970625
0	2,651	Fargo-ND-Gas	2002	Main Gas Steel 2 Inch and Under	26506500
22	27,205	Fargo-ND-Gas	2003	Main Gas Steel Over 10 Inch to 12 Inch	1236 606364
20	1,490	Fargo-ND-Gas	2002	Main Gas Steel Over 2 Inch to 4 Inch	74 483
0	944	Fargo-ND-Gas	2002	Main Gas Steel Over 4 Inch to 8 Inch	9441000
2,630	182,281	Fargo-ND-Gas	2002	Main Gas Steel Over 4 Inch to 8 Inch	69 30844106
3,609	2,707	Fargo-ND-Gas	1968	Main Gas Plastic 2 Inch and Under	0 750199501
3,036	3,586	Fargo-ND-Gas	1969	Main Gas Plastic 2 Inch and Under	1 181231884
1,735	2,464	Fargo-ND-Gas	1970	Main Gas Plastic 2 Inch and Under	1 41995389
17,236	24,986	Fargo-ND-Gas	1970	Main Gas Plastic 2 Inch and Under	1 449611859
452	737	Fargo-ND-Gas	1970	Main Gas Plastic 2 Inch and Under	1 63
11,445	21,173	Fargo-ND-Gas	1971	Main Gas Plastic 2 Inch and Under	1 85
8,582	15,367	Fargo-ND-Gas	1971	Main Gas Plastic 2 Inch and Under	1 790569797
1,545	3,613	Fargo-ND-Gas	1972	Main Gas Plastic 2 Inch and Under	2 338478964
5,893	14,173	Fargo-ND-Gas	1972	Main Gas Plastic 2 Inch and Under	2 404997455
18,509	45,974	Fargo-ND-Gas	1972	Main Gas Plastic 2 Inch and Under	2 483846237
1,628	3,468	Fargo-ND-Gas	1973	Main Gas Plastic 2 Inch and Under	2 13
9,539	26,627	Fargo-ND-Gas	1973	Main Gas Plastic 2 Inch and Under	2 791345005
15,087	32,761	Fargo-ND-Gas	1973	Main Gas Plastic 2 Inch and Under	2 171483396
2,637	6,566	Fargo-ND-Gas	1974	Main Gas Plastic 2 Inch and Under	2 49
4,829	11,639	Fargo-ND-Gas	1974	Main Gas Plastic 2 Inch and Under	2 410207082

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
4,834	19,819	Fargo-ND-Gas	1975	Main Gas Plastic 2 Inch and Under	4 1
11,726	48,822	Fargo-ND-Gas	1975	Main Gas Plastic 2 Inch and Under	4 163586048
20,646	60,295	Fargo-ND-Gas	1976	Main Gas Plastic 2 Inch and Under	2 92039814
32,210	96,952	Fargo-ND-Gas	1976	Main Gas Plastic 2 Inch and Under	3 01
1,939	9,385	Fargo-ND-Gas	1977	Main Gas Plastic 2 Inch and Under	4 84
7,333	36,079	Fargo-ND-Gas	1977	Main Gas Plastic 2 Inch and Under	4 92009955
10,043	40,875	Fargo-ND-Gas	1978	Main Gas Plastic 2 Inch and Under	4 07
686	2,641	Fargo-ND-Gas	1978	Main Gas Plastic 2 Inch and Under	3 849956268
4,138	15,518	Fargo-ND-Gas	1979	Main Gas Plastic 2 Inch and Under	3 75
43,667	162,868	Fargo-ND-Gas	1979	Main Gas Plastic 2 Inch and Under	3 729776719
43,607	250,763	Fargo-ND-Gas	1980	Main Gas Plastic 2 Inch and Under	5 750522393
1,959	10,559	Fargo-ND-Gas	1980	Main Gas Plastic 2 Inch and Under	5 39
70	472	Fargo-ND-Gas	1981	Main Gas Plastic 2 Inch and Under	6 749571429
41,243	280,452	Fargo-ND-Gas	1981	Main Gas Plastic 2 Inch and Under	6 8
39,407	280,578	Fargo-ND-Gas	1982	Main Gas Plastic 2 Inch and Under	7 12
16,756	152,980	Fargo-ND-Gas	1983	Main Gas Plastic 2 Inch and Under	9 12983767
12,298	116,348	Fargo-ND-Gas	1984	Main Gas Plastic 2 Inch and Under	9 460735892
55,631	223,016	Fargo-ND-Gas	1985	Main Gas Plastic 2 Inch and Under	4 00885118
50,625	211,106	Fargo-ND-Gas	1986	Main Gas Plastic 2 Inch and Under	4 17
48,674	164,351	Fargo-ND-Gas	1987	Main Gas Plastic 2 Inch and Under	3 376573119
33,664	151,151	Fargo-ND-Gas	1988	Main Gas Plastic 2 Inch and Under	4 49
29,535	153,260	Fargo-ND-Gas	1989	Main Gas Plastic 2 Inch and Under	5 189094295
48,190	172,975	Fargo-ND-Gas	1990	Main Gas Plastic 2 Inch and Under	3 589435153
27,384	157,858	Fargo-ND-Gas	1991	Main Gas Plastic 2 Inch and Under	5 764614373
60,585	307,015	Fargo-ND-Gas	1992	Main Gas Plastic 2 Inch and Under	5 067510275
145,860	602,073	Fargo-ND-Gas	1993	Main Gas Plastic 2 Inch and Under	4 127742561
45,153	363,694	Fargo-ND-Gas	1994	Main Gas Plastic 2 Inch and Under	8 05469249
36,640	122,846	Fargo-ND-Gas	1995	Main Gas Plastic 2 Inch and Under	3 352774836
54,119	262,180	Fargo-ND-Gas	1996	Main Gas Plastic 2 Inch and Under	4 84451542
114,497	571,556	Fargo-ND-Gas	1997	Main Gas Plastic 2 Inch and Under	4 991890355
100,867	534,100	Fargo-ND-Gas	1998	Main Gas Plastic 2 Inch and Under	5 29509344
65,677	477,705	Fargo-ND-Gas	1999	Main Gas Plastic 2 Inch and Under	7 27355741
57,798	412,432	Fargo-ND-Gas	2000	Main Gas Plastic 2 Inch and Under	7 135747777
528	1,558	Fargo-ND-Gas	1969	Main Gas Plastic Over 2 Inch to 4 Inch	2 95
8,945	22,541	Fargo-ND-Gas	1970	Main Gas Plastic Over 2 Inch to 4 Inch	2 52
1,191	3,716	Fargo-ND-Gas	1970	Main Gas Plastic Over 2 Inch to 4 Inch	3 12
2,538	7,005	Fargo-ND-Gas	1971	Main Gas Plastic Over 2 Inch to 4 Inch	2 76
4,572	16,088	Fargo-ND-Gas	1972	Main Gas Plastic Over 2 Inch to 4 Inch	3 518779528
700	2,912	Fargo-ND-Gas	1972	Main Gas Plastic Over 2 Inch to 4 Inch	4 159442857
2,781	9,400	Fargo-ND-Gas	1973	Main Gas Plastic Over 2 Inch to 4 Inch	3 38
1,269	5,240	Fargo-ND-Gas	1973	Main Gas Plastic Over 2 Inch to 4 Inch	4 129172577
373	1,679	Fargo-ND-Gas	1974	Main Gas Plastic Over 2 Inch to 4 Inch	4 5
1,232	6,739	Fargo-ND-Gas	1975	Main Gas Plastic Over 2 Inch to 4 Inch	5 47
2,825	17,854	Fargo-ND-Gas	1975	Main Gas Plastic Over 2 Inch to 4 Inch	6 32
1,550	6,448	Fargo-ND-Gas	1976	Main Gas Plastic Over 2 Inch to 4 Inch	4 16
14,314	70,711	Fargo-ND-Gas	1976	Main Gas Plastic Over 2 Inch to 4 Inch	4 94
423	3,105	Fargo-ND-Gas	1977	Main Gas Plastic Over 2 Inch to 4 Inch	7 34
3,696	20,143	Fargo-ND-Gas	1978	Main Gas Plastic Over 2 Inch to 4 Inch	5 45
5,362	30,188	Fargo-ND-Gas	1979	Main Gas Plastic Over 2 Inch to 4 Inch	5 63
3,239	30,900	Fargo-ND-Gas	1980	Main Gas Plastic Over 2 Inch to 4 Inch	9 54
6,880	61,989	Fargo-ND-Gas	1981	Main Gas Plastic Over 2 Inch to 4 Inch	9 01
2,716	28,437	Fargo-ND-Gas	1981	Main Gas Plastic Over 2 Inch to 4 Inch	10 47
2,169	23,967	Fargo-ND-Gas	1982	Main Gas Plastic Over 2 Inch to 4 Inch	11 05
2,079	37,318	Fargo-ND-Gas	1983	Main Gas Plastic Over 2 Inch to 4 Inch	17 95
357	6,048	Fargo-ND-Gas	1984	Main Gas Plastic Over 2 Inch to 4 Inch	16 94
447	4,555	Fargo-ND-Gas	1985	Main Gas Plastic Over 2 Inch to 4 Inch	10 19
30,558	252,723	Fargo-ND-Gas	1985	Main Gas Plastic Over 2 Inch to 4 Inch	8 270285686
312	5,220	Fargo-ND-Gas	1986	Main Gas Plastic Over 2 Inch to 4 Inch	16 73
19,443	161,457	Fargo-ND-Gas	1986	Main Gas Plastic Over 2 Inch to 4 Inch	8 304142365
9,868	68,977	Fargo-ND-Gas	1987	Main Gas Plastic Over 2 Inch to 4 Inch	6 99
4,037	15,946	Fargo-ND-Gas	1988	Main Gas Plastic Over 2 Inch to 4 Inch	3 95
8,789	121,640	Fargo-ND-Gas	1988	Main Gas Plastic Over 2 Inch to 4 Inch	13 84
12,186	93,832	Fargo-ND-Gas	1989	Main Gas Plastic Over 2 Inch to 4 Inch	7 7
1,882	31,618	Fargo-ND-Gas	1989	Main Gas Plastic Over 2 Inch to 4 Inch	16 8
5,653	108,658	Fargo-ND-Gas	1990	Main Gas Plastic Over 2 Inch to 4 Inch	19 22121351
866	5,238	Fargo-ND-Gas	1991	Main Gas Plastic Over 2 Inch to 4 Inch	6 048290993
6,204	104,619	Fargo-ND-Gas	1991	Main Gas Plastic Over 2 Inch to 4 Inch	16 86318343
4,707	59,304	Fargo-ND-Gas	1992	Main Gas Plastic Over 2 Inch to 4 Inch	12 59902486
5	43	Fargo-ND-Gas	1993	Main Gas Plastic Over 2 Inch to 4 Inch	8 568
7,084	71,697	Fargo-ND-Gas	1993	Main Gas Plastic Over 2 Inch to 4 Inch	10 12102626
5	162	Fargo-ND-Gas	1994	Main Gas Plastic Over 2 Inch to 4 Inch	32 3
1,979	41,602	Fargo-ND-Gas	1994	Main Gas Plastic Over 2 Inch to 4 Inch	21 02183931
15,899	165,491	Fargo-ND-Gas	1995	Main Gas Plastic Over 2 Inch to 4 Inch	10 40886597
9,628	91,049	Fargo-ND-Gas	1996	Main Gas Plastic Over 2 Inch to 4 Inch	9 456688824
24,419	147,414	Fargo-ND-Gas	1997	Main Gas Plastic Over 2 Inch to 4 Inch	6 036844261
16,399	142,825	Fargo-ND-Gas	1998	Main Gas Plastic Over 2 Inch to 4 Inch	8 709344472
3,152	19,720	Fargo-ND-Gas	1999	Main Gas Plastic Over 2 Inch to 4 Inch	6 256294416
23,469	211,107	Fargo-ND-Gas	1999	Main Gas Plastic Over 2 Inch to 4 Inch	8 995146363

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
12,030	106,705	Fargo-ND-Gas	2000	Main Gas Plastic Over 2 Inch to 4 Inch	8 86987448
15,000	85,693	Fargo-ND-Gas	1993	Main Gas Plastic Over 4 Inch to 8 Inch	5 712898
8,900	247,425	Fargo-ND-Gas	1995	Main Gas Plastic Over 4 Inch to 8 Inch	27 80057079
638	46,469	Fargo-ND-Gas	1996	Main Gas Plastic Over 4 Inch to 8 Inch	72 83619122
80,590	1,025,107	Fargo-ND-Gas	1997	Main Gas Plastic Over 4 Inch to 8 Inch	12 7200232
20,887	300,625	Fargo-ND-Gas	1998	Main Gas Plastic Over 4 Inch to 8 Inch	14 39290755
7,813	193,172	Fargo-ND-Gas	1999	Main Gas Plastic Over 4 Inch to 8 Inch	24 72438756
7,140	106,779	Fargo-ND-Gas	2000	Main Gas Plastic Over 4 Inch to 8 Inch	14 95497199
1,659	43,178	Fargo-ND-Gas	2001	Main Gas Plastic 2 Inch and Under	26 02642556
20,040	31,351	Fargo-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	1 564402196
67,736	1,090,530	Fargo-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	16 09971537
65,057	307,176	Fargo-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	4 721637948
650	4,939	Fargo-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	7 598153846
6,324	35,480	Fargo-ND-Gas	2003	Main Gas Plastic 2 Inch and Under	5 610336812
5,235	29,537	Fargo-ND-Gas	2003	Main Gas Plastic 2 Inch and Under	5 642221585
2,443	13,250	Fargo-ND-Gas	2004	Main Gas Plastic 2 Inch and Under	5 423778142
2,800	10,471	Fargo-ND-Gas	2001	Main Gas Plastic Over 2 Inch to 4 Inch	3 739621429
19,011	175,559	Fargo-ND-Gas	2002	Main Gas Plastic Over 2 Inch to 4 Inch	9 234589448
2,329	24,556	Fargo-ND-Gas	2002	Main Gas Plastic Over 2 Inch to 4 Inch	10 54376127
840	9,903	Fargo-ND-Gas	2003	Main Gas Plastic Over 2 Inch to 4 Inch	11 78952381
560	10,978	Fargo-ND-Gas	2003	Main Gas Plastic Over 2 Inch to 4 Inch	19 60392857
39,990	180,153	Fargo-ND-Gas	2001	Main Gas Plastic Over 4 Inch to 8 Inch	4 504951988
16,113	595,685	Fargo-ND-Gas	2002	Main Gas Plastic Over 4 Inch to 8 Inch	36 96922919
4,240	185,700	Fargo-ND-Gas	2002	Main Gas Plastic Over 4 Inch to 8 Inch	43 79721226
2,025	23,032	Fargo-ND-Gas	2003	Main Gas Plastic Over 4 Inch to 8 Inch	11 37382222
200	5,910	Fargo-ND-Gas	2002	Main Gas Steel 2 Inch and Under	29 54825
86,598	202,972	Grand Forks-ND-Gas	1962	Main Gas Steel 2 Inch and Under	2 343836001
17,181	42,953	Grand Forks-ND-Gas	1963	Main Gas Steel 2 Inch and Under	2 5
79	137	Grand Forks-ND-Gas	1964	Main Gas Steel 2 Inch and Under	1 74
154	305	Grand Forks-ND-Gas	1964	Main Gas Steel 2 Inch and Under	1 98
10,028	25,070	Grand Forks-ND-Gas	1964	Main Gas Steel 2 Inch and Under	2 5
103	222	Grand Forks-ND-Gas	1965	Main Gas Steel 2 Inch and Under	2 159126214
11,213	35,209	Grand Forks-ND-Gas	1965	Main Gas Steel 2 Inch and Under	3 14
980	1,975	Grand Forks-ND-Gas	1966	Main Gas Steel 2 Inch and Under	2 01494898
436	1,029	Grand Forks-ND-Gas	1966	Main Gas Steel 2 Inch and Under	2 36
3,788	11,175	Grand Forks-ND-Gas	1966	Main Gas Steel 2 Inch and Under	2 95
642	1,394	Grand Forks-ND-Gas	1967	Main Gas Steel 2 Inch and Under	2 170965732
660	1,696	Grand Forks-ND-Gas	1967	Main Gas Steel 2 Inch and Under	2 57
3,232	10,278	Grand Forks-ND-Gas	1967	Main Gas Steel 2 Inch and Under	3 18
220	781	Grand Forks-ND-Gas	1968	Main Gas Steel 2 Inch and Under	3 55
7,730	34,476	Grand Forks-ND-Gas	1968	Main Gas Steel 2 Inch and Under	4 46
105	215	Grand Forks-ND-Gas	1969	Main Gas Steel 2 Inch and Under	2 05
867	2,220	Grand Forks-ND-Gas	1969	Main Gas Steel 2 Inch and Under	2 56
55	192	Grand Forks-ND-Gas	1973	Main Gas Steel 2 Inch and Under	3 497454545
292	1,126	Grand Forks-ND-Gas	1973	Main Gas Steel 2 Inch and Under	3 857089041
241	11,501	Grand Forks-ND-Gas	1975	Main Gas Steel 2 Inch and Under	47 72
61	1,955	Grand Forks-ND-Gas	1976	Main Gas Steel 2 Inch and Under	32 04868852
850	17,677	Grand Forks-ND-Gas	1978	Main Gas Steel 2 Inch and Under	20 79609412
214	848	Grand Forks-ND-Gas	1985	Main Gas Steel 2 Inch and Under	3 963130841
20	2,585	Grand Forks-ND-Gas	1986	Main Gas Steel 2 Inch and Under	129 2275
46	756	Grand Forks-ND-Gas	1990	Main Gas Steel 2 Inch and Under	16 44065217
21	1,708	Grand Forks-ND-Gas	1995	Main Gas Steel 2 Inch and Under	81 34190476
13,584	43,078	Grand Forks-ND-Gas	1962	Main Gas Steel Over 2 Inch to 4 Inch	3 171257362
34,614	130,698	Grand Forks-ND-Gas	1962	Main Gas Steel Over 2 Inch to 4 Inch	3 775871902
3,521	11,971	Grand Forks-ND-Gas	1963	Main Gas Steel Over 2 Inch to 4 Inch	3 4
6,789	27,631	Grand Forks-ND-Gas	1963	Main Gas Steel Over 2 Inch to 4 Inch	4 07
2,487	9,028	Grand Forks-ND-Gas	1964	Main Gas Steel Over 2 Inch to 4 Inch	3 63
3,150	14,616	Grand Forks-ND-Gas	1964	Main Gas Steel Over 2 Inch to 4 Inch	4 64
1,556	6,971	Grand Forks-ND-Gas	1965	Main Gas Steel Over 2 Inch to 4 Inch	4 48
7,019	38,675	Grand Forks-ND-Gas	1965	Main Gas Steel Over 2 Inch to 4 Inch	5 51
1,022	4,323	Grand Forks-ND-Gas	1966	Main Gas Steel Over 2 Inch to 4 Inch	4 23
2,685	14,069	Grand Forks-ND-Gas	1966	Main Gas Steel Over 2 Inch to 4 Inch	5 24
2,639	11,955	Grand Forks-ND-Gas	1967	Main Gas Steel Over 2 Inch to 4 Inch	4 53
8,030	44,647	Grand Forks-ND-Gas	1967	Main Gas Steel Over 2 Inch to 4 Inch	5 56
1,190	7,497	Grand Forks-ND-Gas	1968	Main Gas Steel Over 2 Inch to 4 Inch	6 3
2,353	17,930	Grand Forks-ND-Gas	1968	Main Gas Steel Over 2 Inch to 4 Inch	7 62
2,552	11,918	Grand Forks-ND-Gas	1969	Main Gas Steel Over 2 Inch to 4 Inch	4 67
165	1,095	Grand Forks-ND-Gas	1973	Main Gas Steel Over 2 Inch to 4 Inch	6 636727273
162	690	Grand Forks-ND-Gas	1974	Main Gas Steel Over 2 Inch to 4 Inch	4 26
223	1,413	Grand Forks-ND-Gas	1985	Main Gas Steel Over 2 Inch to 4 Inch	6 337578475
75	4,202	Grand Forks-ND-Gas	1990	Main Gas Steel Over 2 Inch to 4 Inch	56 03106667
30	739	Grand Forks-ND-Gas	1990	Main Gas Steel Over 2 Inch to 4 Inch	24 64333333
138	27,186	Grand Forks-ND-Gas	1997	Main Gas Steel Over 2 Inch to 4 Inch	196 9972464
290	8,654	Grand Forks-ND-Gas	1999	Main Gas Steel Over 2 Inch to 4 Inch	29 84241379
84	1,359	Grand Forks-ND-Gas	2000	Main Gas Steel Over 2 Inch to 4 Inch	16 17630952
7,982	75,270	Grand Forks-ND-Gas	1961	Main Gas Steel Over 4 Inch to 8 Inch	9 43
11,317	64,797	Grand Forks-ND-Gas	1962	Main Gas Steel Over 4 Inch to 8 Inch	5 725605726
7,528	56,003	Grand Forks-ND-Gas	1962	Main Gas Steel Over 4 Inch to 8 Inch	7 439314559

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
805	4,766	Grand Forks-ND-Gas	1964	Main Gas Steel Over 4 Inch to 8 Inch	5 92
24	196	Grand Forks-ND-Gas	1964	Main Gas Steel Over 4 Inch to 8 Inch	8 15
1,597	11,003	Grand Forks-ND-Gas	1965	Main Gas Steel Over 4 Inch to 8 Inch	6 89
2,382	22,391	Grand Forks-ND-Gas	1965	Main Gas Steel Over 4 Inch to 8 Inch	9 4
2,028	13,365	Grand Forks-ND-Gas	1966	Main Gas Steel Over 4 Inch to 8 Inch	6 59
728	6,559	Grand Forks-ND-Gas	1966	Main Gas Steel Over 4 Inch to 8 Inch	9 01
287	1,992	Grand Forks-ND-Gas	1967	Main Gas Steel Over 4 Inch to 8 Inch	6 94
1,416	13,325	Grand Forks-ND-Gas	1968	Main Gas Steel Over 4 Inch to 8 Inch	9 41
1,166	14,843	Grand Forks-ND-Gas	1968	Main Gas Steel Over 4 Inch to 8 Inch	12 73
86	2,350	Grand Forks-ND-Gas	1970	Main Gas Steel Over 4 Inch to 8 Inch	27 32813953
7,942	55,937	Grand Forks-ND-Gas	1971	Main Gas Steel Over 4 Inch to 8 Inch	7 043198187
10,629	72,573	Grand Forks-ND-Gas	1972	Main Gas Steel Over 4 Inch to 8 Inch	6 827845517
5,120	48,808	Grand Forks-ND-Gas	1973	Main Gas Steel Over 4 Inch to 8 Inch	9 532791016
79	3,372	Grand Forks-ND-Gas	1978	Main Gas Steel Over 4 Inch to 8 Inch	42 68797468
502	7,044	Grand Forks-ND-Gas	1985	Main Gas Steel Over 4 Inch to 8 Inch	14 03151394
25	312	Grand Forks-ND-Gas	1985	Main Gas Steel Over 4 Inch to 8 Inch	12 4712
24	6,898	Grand Forks-ND-Gas	1986	Main Gas Steel Over 4 Inch to 8 Inch	287 43625
5,860	138,106	Grand Forks-ND-Gas	1990	Main Gas Steel Over 4 Inch to 8 Inch	23 56756314
1,662	73,035	Grand Forks-ND-Gas	1993	Main Gas Steel Over 4 Inch to 8 Inch	43 94430806
68	7,652	Grand Forks-ND-Gas	1994	Main Gas Steel Over 4 Inch to 8 Inch	112 5297059
367	24,535	Grand Forks-ND-Gas	1995	Main Gas Steel Over 4 Inch to 8 Inch	66 85160763
7,498	142,776	Grand Forks-ND-Gas	1999	Main Gas Steel Over 4 Inch to 8 Inch	19 04184983
17,068	618,653	Grand Forks-ND-Gas	2000	Main Gas Steel Over 4 Inch to 8 Inch	36 2463663
4,048	54,162	Grand Forks-ND-Gas	1961	Main Gas Steel Over 10 Inch to 12 Inch	13 38
1,105	15,183	Grand Forks-ND-Gas	1965	Main Gas Steel Over 10 Inch to 12 Inch	13 74
2	26	Grand Forks-ND-Gas	1966	Main Gas Steel Over 10 Inch to 12 Inch	13 22
62,551	1,147,342	Grand Forks-ND-Gas	1985	Main Gas Steel Over 10 Inch to 12 Inch	18 34250308
7,045	157,487	Grand Forks-ND-Gas	1986	Main Gas Steel Over 10 Inch to 12 Inch	22 35441164
11,203	194,820	Grand Forks-ND-Gas	1961	Main Gas Steel Over 12 Inch to 20 Inch	17 39
280	635	Grand Forks-ND-Gas	1970	Main Gas Plastic 2 Inch and Under	2 268571429
2,409	4,529	Grand Forks-ND-Gas	1971	Main Gas Plastic 2 Inch and Under	1 88
8,272	16,213	Grand Forks-ND-Gas	1971	Main Gas Plastic 2 Inch and Under	1 96
4,833	11,406	Grand Forks-ND-Gas	1972	Main Gas Plastic 2 Inch and Under	2 36007035
5,536	13,532	Grand Forks-ND-Gas	1972	Main Gas Plastic 2 Inch and Under	2 444282876
4,623	9,338	Grand Forks-ND-Gas	1973	Main Gas Plastic 2 Inch and Under	2 02
22,548	46,900	Grand Forks-ND-Gas	1973	Main Gas Plastic 2 Inch and Under	2 08
2,122	5,751	Grand Forks-ND-Gas	1974	Main Gas Plastic 2 Inch and Under	2 71
5,196	14,601	Grand Forks-ND-Gas	1974	Main Gas Plastic 2 Inch and Under	2 81
387	1,219	Grand Forks-ND-Gas	1975	Main Gas Plastic 2 Inch and Under	3 15
21,718	70,149	Grand Forks-ND-Gas	1975	Main Gas Plastic 2 Inch and Under	3 23
131	796	Grand Forks-ND-Gas	1976	Main Gas Plastic 2 Inch and Under	6 08
23,083	143,345	Grand Forks-ND-Gas	1976	Main Gas Plastic 2 Inch and Under	6 209999567
7,483	45,793	Grand Forks-ND-Gas	1977	Main Gas Plastic 2 Inch and Under	6 119659228
685	3,247	Grand Forks-ND-Gas	1978	Main Gas Plastic 2 Inch and Under	4 74
25,781	128,035	Grand Forks-ND-Gas	1978	Main Gas Plastic 2 Inch and Under	4 966256933
9,594	50,848	Grand Forks-ND-Gas	1979	Main Gas Plastic 2 Inch and Under	5 3
23,739	139,111	Grand Forks-ND-Gas	1980	Main Gas Plastic 2 Inch and Under	5 86
4,401	21,961	Grand Forks-ND-Gas	1981	Main Gas Plastic 2 Inch and Under	4 99
3,252	11,902	Grand Forks-ND-Gas	1982	Main Gas Plastic 2 Inch and Under	3 66
13,376	49,090	Grand Forks-ND-Gas	1983	Main Gas Plastic 2 Inch and Under	3 67
10,832	48,852	Grand Forks-ND-Gas	1984	Main Gas Plastic 2 Inch and Under	4 51
23,116	107,097	Grand Forks-ND-Gas	1985	Main Gas Plastic 2 Inch and Under	4 633042914
30,231	125,767	Grand Forks-ND-Gas	1986	Main Gas Plastic 2 Inch and Under	4 160204757
22,272	73,721	Grand Forks-ND-Gas	1987	Main Gas Plastic 2 Inch and Under	3 310033226
10,730	67,170	Grand Forks-ND-Gas	1988	Main Gas Plastic 2 Inch and Under	6 26
16,078	66,954	Grand Forks-ND-Gas	1989	Main Gas Plastic 2 Inch and Under	4 164323299
17,215	61,236	Grand Forks-ND-Gas	1990	Main Gas Plastic 2 Inch and Under	3 557121696
15,944	53,242	Grand Forks-ND-Gas	1991	Main Gas Plastic 2 Inch and Under	3 339300677
20,710	83,039	Grand Forks-ND-Gas	1992	Main Gas Plastic 2 Inch and Under	4 009629648
17,268	69,613	Grand Forks-ND-Gas	1993	Main Gas Plastic 2 Inch and Under	4 031324994
25,952	74,295	Grand Forks-ND-Gas	1994	Main Gas Plastic 2 Inch and Under	2 862778977
16,634	59,039	Grand Forks-ND-Gas	1995	Main Gas Plastic 2 Inch and Under	3 549320669
2,739	6,711	Grand Forks-ND-Gas	1996	Main Gas Plastic 2 Inch and Under	2 450193501
53,975	565,872	Grand Forks-ND-Gas	1997	Main Gas Plastic 2 Inch and Under	10 48395553
19,097	41,993	Grand Forks-ND-Gas	1998	Main Gas Plastic 2 Inch and Under	2 198917631
39,499	204,076	Grand Forks-ND-Gas	1999	Main Gas Plastic 2 Inch and Under	5 166608522
81,127	329,319	Grand Forks-ND-Gas	2000	Main Gas Plastic 2 Inch and Under	4 059296165
4,766	16,975	Grand Forks-ND-Gas	1971	Main Gas Plastic Over 2 Inch to 4 Inch	3 561705833
1,827	6,376	Grand Forks-ND-Gas	1972	Main Gas Plastic Over 2 Inch to 4 Inch	3 49
6,069	25,356	Grand Forks-ND-Gas	1972	Main Gas Plastic Over 2 Inch to 4 Inch	4 177960125
4,534	6,529	Grand Forks-ND-Gas	1973	Main Gas Plastic Over 2 Inch to 4 Inch	1 44
2,223	7,900	Grand Forks-ND-Gas	1973	Main Gas Plastic Over 2 Inch to 4 Inch	3 553729195
1,848	7,300	Grand Forks-ND-Gas	1974	Main Gas Plastic Over 2 Inch to 4 Inch	3 95
257	1,213	Grand Forks-ND-Gas	1974	Main Gas Plastic Over 2 Inch to 4 Inch	4 72
3,475	15,116	Grand Forks-ND-Gas	1975	Main Gas Plastic Over 2 Inch to 4 Inch	4 35
1,244	6,344	Grand Forks-ND-Gas	1975	Main Gas Plastic Over 2 Inch to 4 Inch	5 1
991	7,730	Grand Forks-ND-Gas	1976	Main Gas Plastic Over 2 Inch to 4 Inch	7 8
509	4,530	Grand Forks-ND-Gas	1976	Main Gas Plastic Over 2 Inch to 4 Inch	8 9

Quantity (ft)	Total Cost ($)	Location	Year	Description	Cost/ ft
304	2,484	Grand Forks-ND-Gas	1977	Main Gas Plastic Over 2 Inch to 4 Inch	8 17
375	2,483	Grand Forks-ND-Gas	1978	Main Gas Plastic Over 2 Inch to 4 Inch	6 62
2,353	18,142	Grand Forks-ND-Gas	1978	Main Gas Plastic Over 2 Inch to 4 Inch	7 71
614	4,298	Grand Forks-ND-Gas	1979	Main Gas Plastic Over 2 Inch to 4 Inch	7
2,015	16,837	Grand Forks-ND-Gas	1979	Main Gas Plastic Over 2 Inch to 4 Inch	8 355761787
638	4,932	Grand Forks-ND-Gas	1980	Main Gas Plastic Over 2 Inch to 4 Inch	7 73
11,208	100,610	Grand Forks-ND-Gas	1980	Main Gas Plastic Over 2 Inch to 4 Inch	8 976642577
852	4,524	Grand Forks-ND-Gas	1982	Main Gas Plastic Over 2 Inch to 4 Inch	5 31
2,588	16,563	Grand Forks-ND-Gas	1982	Main Gas Plastic Over 2 Inch to 4 Inch	6 4
3,131	24,872	Grand Forks-ND-Gas	1983	Main Gas Plastic Over 2 Inch to 4 Inch	7 943660172
2,220	17,973	Grand Forks-ND-Gas	1984	Main Gas Plastic Over 2 Inch to 4 Inch	8 096135135
5,730	35,354	Grand Forks-ND-Gas	1985	Main Gas Plastic Over 2 Inch to 4 Inch	6 17
13,319	115,076	Grand Forks-ND-Gas	1985	Main Gas Plastic Over 2 Inch to 4 Inch	8 64
6,307	37,527	Grand Forks-ND-Gas	1986	Main Gas Plastic Over 2 Inch to 4 Inch	5 95
2,334	19,396	Grand Forks-ND-Gas	1986	Main Gas Plastic Over 2 Inch to 4 Inch	8 31
1,275	8,836	Grand Forks-ND-Gas	1987	Main Gas Plastic Over 2 Inch to 4 Inch	6 93
1,321	13,256	Grand Forks-ND-Gas	1988	Main Gas Plastic Over 2 Inch to 4 Inch	10 03495079
1,782	13,864	Grand Forks-ND-Gas	1989	Main Gas Plastic Over 2 Inch to 4 Inch	7 78
351	3,533	Grand Forks-ND-Gas	1990	Main Gas Plastic Over 2 Inch to 4 Inch	10 06555556
4,310	55,070	Grand Forks-ND-Gas	1990	Main Gas Plastic Over 2 Inch to 4 Inch	12 77732947
987	6,860	Grand Forks-ND-Gas	1991	Main Gas Plastic Over 2 Inch to 4 Inch	6 950445795
4,286	54,854	Grand Forks-ND-Gas	1991	Main Gas Plastic Over 2 Inch to 4 Inch	12 79837378
2,433	35,097	Grand Forks-ND-Gas	1992	Main Gas Plastic Over 2 Inch to 4 Inch	14 42519523
1,855	15,695	Grand Forks-ND-Gas	1993	Main Gas Plastic Over 2 Inch to 4 Inch	8 461088949
11,177	100,369	Grand Forks-ND-Gas	1994	Main Gas Plastic Over 2 Inch to 4 Inch	8 979931109
5,934	51,974	Grand Forks-ND-Gas	1995	Main Gas Plastic Over 2 Inch to 4 Inch	8 75864004
12,420	194,532	Grand Forks-ND-Gas	1997	Main Gas Plastic Over 2 Inch to 4 Inch	15 662781
891	5,703	Grand Forks-ND-Gas	1998	Main Gas Plastic Over 2 Inch to 4 Inch	6 40037037
24,459	202,011	Grand Forks-ND-Gas	1999	Main Gas Plastic Over 2 Inch to 4 Inch	8 259187211
22,025	191,028	Grand Forks-ND-Gas	2000	Main Gas Plastic Over 2 Inch to 4 Inch	8 673224972
9,160	206,667	Grand Forks-ND-Gas	1997	Main Gas Plastic Over 4 Inch to 8 Inch	22 56194323
7,229	111,868	Grand Forks-ND-Gas	1999	Main Gas Plastic Over 4 Inch to 8 Inch	15 47486098
69,694	696,028	Grand Forks-ND-Gas	2000	Main Gas Plastic Over 4 Inch to 8 Inch	9 986908916
7,329	35,011	Grand Forks-ND-Gas	2001	Main Gas Plastic 2 Inch and Under	4 777116933
384	325	Grand Forks-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	0 846015625
4,918	11,760	Grand Forks-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	2 391116307
175	849	Grand Forks-ND-Gas	2002	Main Gas Plastic 2 Inch and Under	4 853314286
6,929	40,167	Grand Forks-ND-Gas	2003	Main Gas Plastic 2 Inch and Under	5 796959157
5,646	28,115	Grand Forks-ND-Gas	2003	Main Gas Plastic 2 Inch and Under	4 979624513
2,020	10,144	Grand Forks-ND-Gas	2004	Main Gas Plastic 2 Inch and Under	5 021648515
2,321	18,667	Grand Forks-ND-Gas	2001	Main Gas Plastic Over 2 Inch to 4 Inch	8 042692805
1,212	7,237	Grand Forks-ND-Gas	2002	Main Gas Plastic Over 2 Inch to 4 Inch	5 970907591
978	4,887	Grand Forks-ND-Gas	2003	Main Gas Plastic Over 2 Inch to 4 Inch	4 997372188
944	14,386	Grand Forks-ND-Gas	2001	Main Gas Plastic Over 4 Inch to 8 Inch	15 23965042
685	27,832	Grand Forks-ND-Gas	2002	Main Gas Plastic Over 4 Inch to 8 Inch	40 63024818
4,076,716	30,112,776				7 3865
2,185,436	11,207,245			Two Inch Main	$5 1282
53 6%	0				69 43%
4,076,716	20,906,215			Minimum System	$5 1282
	1				69 43%

Northern States Power Company
Gas Utility - North Dakota
Revenue Apportionment
Test Year Ending December 31, 2004

Case No. PU-400-04-578
Exhibit No. _____(NNP-1)
Schedule 3, Page 1 of 1

	Present Revenue	CCOSS Responsibility	Increase w/o Design Chg	Present Rev as % Cost	% Increase to Pay Cost	Proposed Rev	Proposed $ Increase	Proposed % Increase
Residential	$26,361,011	$29,646,000	$26,850,921	88 9%	12.5%	$27,577,162	$1,216,151	4 6%
Small Commercial	$30,884,941	$29,995,000	$31,459,306	103.0%	-2 9%	$30,886,270	$1,329	0.0%
Small Interruptible	$3,912,461	$3,554,000	$3,985,221	110.1%	-9.2%	$3,938,974	$26,513	0.7%
Large Interruptible (Incl Lg Int Transport)	$7,682,678	$6,926,000	$7,825,552	110.9%	-9.8%	$7,713,308	$30,629	0 4%
Total Retail	$68,841,092	$70,121,000	$70,121,000	98.2%	1.9%	$70,115,715	$1,274,622	1 9%
Other Revenues	$2,765,694					$2,771,304	$5,610	0.2%
Total Increase							$1,280,232	1 8%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Summary of Present and Proposed Rates

Case No. PU-400-04-578
Exhibit No. _____(NNP-
Schedule 4, Page 1 of 1

Customer Class	Proposed Monthly Basic Service Charge	Monthly Customer Cost
Residential	$ 8.50	$17.99
Firm Commercial	$ 20.00	$31.89
Small Interruptible	$ 75.00	$71.30
Large Interruptible	$ 275.00	$138.47

DECLINING USE PER CUSTOMER:
DESCRIPTION OF OTHER INITIATIVES

Approach	Examples
Weather Normalization	Montana-Dakota Utilities implemented a revenue decoupling mechanism called the "Delivery Distribution Stabilization Mechanism" in North Dakota in 2004. The mechanism recovers variations in customer usage brought about by weather fluctuations during the heating season, defined as November 1 through March 31st.
Price Elasticity/ Conservation Adjustments	Washington Gas Light (WGL) received approval for a "Repression Adjustment" that reflects an adjustment to test-year revenue levels to reflect the price elasticity of demand that has resulted from improved energy efficiency and contributed to a decline in use per customer (e.g., the replacement of older, inefficient equipment with newer, more energy efficient equipment).
Higher Customer Charges	Gas utilities, including CenterPoint Energy Minnegasco and Wisconsin Public Service, are seeking substantially higher customer charges as part of their rate case filing. Examples of recent customer charges include: Wisconsin Public Service's request for an increase from $10.50 to $14.50 and Ameren UE's' increase to $15.00 per month in Illinois.
Declining Block Rates	A number of gas utilities throughout the U.S., including National Fuel, Nicor and Keyspan, have declining block rates in place today. For example, Keyspan (New England) has a two-step declining block rate for residential heating customers with the first step, representing the first 150 therms during the winter, at a rate roughly $1.60 per Dth higher than the second step.
'Partial' Revenue Decoupling	Northwest Natural in Portland, Oregon has a 'Partial' Revenue Decoupling mechanism under which they recover 90% of the margin difference between normalized actual use per customer and a baseline use per customer. The mechanism is referred to as 'Partial" since it doesn't include weather normalization. (However, Northwest Natural subsequent to the approval of its 'Partial' Decoupling mechanism did receive approval for a weather normalization mechanism.) Northwest Natural established a balancing account to defer/ amortize 90% of the margin differential between weather-normalized actual usage and baseline usage. The mechanism was established in accordance with a Stipulation and Agreement adopted by the Oregon Public Utilities Commission in Docket UG 143, Order No 02-634 dated September 12, 2002.

DECLINING USE PER CUSTOMER:
DESCRIPTION OF OTHER INITIATIVES

Approach	Examples
Weather Normalization	A number of gas utilities throughout the U.S., including Atmos and Keyspan (NY), have a weather normalization mechanism. Weather normalization mechanisms adjust for the revenue difference between actual and normal degree-days (as approved in the most recent rate case). Thus, as weather becomes gradually warmer over time, the weather normalization mechanism neutralizes the impact of the warm weather trend.
100% Fixed Rate	Atlanta Gas Light implemented 100% fixed rates for distribution costs several years ago. All distribution margin is recovered through two mechanisms: (a) a customer charge, which recovers the customer connection costs, including the meter, regulator, service line and meter reading expense; and (b) a capacity charge, which recovers all common distribution costs of providing delivery service based on a customer's contribution to peak demand on the coldest day of the year. Customer peak demand is recalculated each year to reflect changes usage patterns and gas appliances, and (in contrast to typical demand charges), the capacity charge varies throughout the year to reflect the seasonal nature of gas consumption.
'Full" Revenue Decoupling	Baltimore Gas & Electric implemented a 'Full' Revenue Decoupling mechanism several years ago. The mechanism recovers variations in customer usage brought about by weather variations from normal, declining consumption brought about by improved energy efficient equipment, and other variations in customer consumption. The adjustment mechanism is 2-way – with customers and shareholders sharing equally in variations from levels approved in the most recent rate case. The adjustment is based on use per customer – enabling BG&E to retain revenues from load growth to offset the cost of adding customers. Rates are adjusted monthly to reflect the differences between actual and the baseline use per customer.

ILLUSTRATIVE DERIVATION OF RESIDENTIAL WEATHER NORMALIZED USE PER CUSTOMER ADJUSTMENT FACTOR

(All sales are in therms)

		TEST YEAR			FISCAL YEAR ZERO						
Line No	Month	Sales	Customer Bills	Use Per Customer	Actual Sales	W/N Sales	Customer Bills	W/N Use Per Cust	Usage Difference	Distrib Chg ($/Therm)	Over/Under Recovery
	(1)	(2)	(3)	(2 / 3 = 4)	(5)	(6)	(7)	(6 / 7 = 8)	(4 - 8 = 9)	(10)	(3 x 9 x 10 = 11)
1	Jan	5,708,110	34,541	165 26	5,868,379	5,753,313	35,405	162 50	2 76	$0 12388	$11,810
2	Feb	4,647,630	34,530	134 60	4,871,635	4,684,264	35,393	132 35	2 25	$0 12388	$9,625
3	Mar	3,891,270	34,618	112 41	3,882,717	3,921,936	35,483	110 53	1 88	$0 12388	$8,062
4	Apr	2,172,850	34,506	62 97	2,211,948	2,190,048	35,369	61 92	1 05	$0 12388	$4,488
5	May	854,750	34,430	24 83	870,068	861,453	35,291	24 41	0 42	$0 12388	$1,791
6	Jun	472,670	34,400	13 74	476,363	476,363	35,260	13 51	0 23	$0 12388	$980
7	Jul	405,120	34,344	11 80	408,355	408,355	35,203	11 60	0 20	$0 12388	$851
8	Aug	383,340	34,323	11 17	386,287	386,287	35,181	10 98	0 19	$0 12388	$808
9	Sep	698,080	34,364	20 31	689,335	703,403	35,223	19 97	0 34	$0 12388	$1,447
10	Oct	1,819,340	34,586	52 60	1,888,532	1,833,526	35,451	51 72	0 88	$0 12388	$3,770
11	Nov	3,680,100	34,854	105 59	3,671,880	3,708,970	35,725	103 82	1 77	$0 12388	$7,642
12	Dec	5,453,360	35,145	155 17	5,771,369	5,496,542	36,024	152 58	2 59	$0 12388	$11,276
13	**Total**	30,186,620	414,641	870 45	30,996,868	30,424,460	425,008	855 89	14 56		**$62,550**

		TEST YEAR			FISCAL YEAR ONE						
Line No	Month	Sales	Customer Bills	Use Per Customer	Actual Sales	W/N Sales	Customer Bills	W/N Use Per Cust	Usage Difference	Distrib Chg ($/Therm)	Over/Under Recovery
	(1)	(2)	(3)	(2 / 3 = 4)	(5)	(6)	(7)	(6 / 7 = 8)	(4 - 8 = 9)	(10)	(3 x 9 x 10 = 11)
1	Jan	5,708,110	34,541	165 26	5,740,432	5,798,416	36,290	159 78	5 48	$0 12388	$23,449
2	Feb	4,647,630	34,530	134 60	4,626,795	4,721,219	36,278	130 14	4 46	$0 12388	$19,078
3	Mar	3,891,270	34,618	112 41	4,031,746	3,952,692	36,370	108 68	3 73	$0 12388	$15,996
4	Apr	2,172,850	34,506	62 97	2,140,871	2,207,083	36,253	60 88	2 09	$0 12388	$8,934
5	May	854,750	34,430	24 83	850,789	868,152	36,173	24 00	0 83	$0 12388	$3,540
6	Jun	472,670	34,400	13 74	479,966	479,966	36,142	13 28	0 46	$0 12388	$1,960
7	Jul	405,120	34,344	11 80	411,707	411,707	36,083	11 41	0 39	$0 12388	$1,659
8	Aug	383,340	34,323	11 17	389,459	389,459	36,061	10 80	0 37	$0 12388	$1,573
9	Sep	698,080	34,364	20 31	716,174	709,083	36,104	19 64	0 67	$0 12388	$2,852
10	Oct	1,819,340	34,586	52 60	1,792,657	1,848,100	36,337	50 86	1 74	$0 12388	$7,455
11	Nov	3,680,100	34,854	105 59	3,588,446	3,737,965	36,618	102 08	3 51	$0 12388	$15,155
12	Dec	5,453,360	35,145	155 17	5,650,655	5,539,858	36,925	150 03	5 14	$0 12388	$22,378
13	**Total**	30,186,620	414,641	870 45	30,419,697	30,663,700	435,634	841 58	28 87		**$124,029**

ILLUSTRATIVE DERIVATION OF RESIDENTIAL WEATHER NORMALIZED USE PER CUSTOMER ADJUSTMENT FACTOR

(All sales are in therms)

	PREVIOUS YR			CURRENT YEAR					
Current Year	Adjustment For W/N Use Per Customer (1)	Under/Over Recovery (2)	Total Adjustments (1 + 2 = 3)	Previous Year Adjustments, With Carrying Costs (4)	Budgeted Sales (5)	Adjust Factor ($/Therm) (4 / 5 = 6)	Actual Sales (7)	Actual Recovery (6 x 7 = 8)	Under/Over Recovery (4 - 8 = 9)
1	$62,550	$0	$62,550	$70,994	30,663,700	$0 00232	30,419,697	$70,429	$565
2	$124,029	$565	$124,594	$141,414	30,904,909	$0 00458	31,000,000	$141,849	-$435
3		-$435							

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DIRECT TESTIMONY
DR. KARL A. MCDERMOTT
NORTHERN STATES POWER COMPANY D/B/A
XCEL ENERGY
HEARING EXHIBIT NO. _____

DIRECT TESTIMONY OF

KARL A. MCDERMOTT, PH.D

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company
d/b/a Xcel Energy
Notice of Change in Rates
For Natural Gas Service

December 1, 2004

DIRECT TESTIMONY OF
KARL A. MCDERMOTT, PH. D.

I. QUALIFICATIONS, PURPOSE AND CONCLUSIONS

Q. Please state your name, business address and current position

A. My name is Dr. Karl A. McDermott. I am a Vice President of National Economic Research Associates, Inc. (NERA). My business address is 875 North Michigan Avenue, Suite 3650, Chicago, Illinois 60611.

Q. Please state your qualifications.

A. I have been working in the field of public utility regulation for over twenty-five years. In 1999 I joined NERA's energy practice in its Chicago office where I direct projects in the electric, natural gas and telecommunications industries.

From April of 1992 until May of 1998, I served as a Commissioner on the Illinois Commerce Commission (ICC). The ICC regulates electric, natural gas and telephone utilities operating within the state of Illinois. While a Commissioner at the ICC, I was responsible for helping make regulatory policy, along with my fellow Commissioners, as well as implementing the ICC's policies. In the time I was a member of the ICC I presided over many electric, gas, telephone and water public utility rate proceedings including deciding issues related to the fair return on equity and the overall rate of return for these companies.

While a Commissioner I was very active in the national regulatory debate through my affiliation with the National Regulatory Utility Commissioners (NARUC) organization where I was a member of the Committee on Energy and the Environment from 1992 through 1998. For the last two years of my tenure at NARUC I was the Chair of the Subcommittee on the Environment.

From 1986 to 1992, I was co-founder and served as the President of the Center for Regulatory Studies (CRS), a not-for-profit regulatory policy institute located on the campus of Illinois State University. CRS was created to provide the Illinois regulatory environment

with independent third-party research and education on issues affecting the regulation of public utilities.

Before co-founding the CRS, I worked in numerous capacities including positions on the staff of the ICC, the NARUC-sponsored National Regulatory Research Institute (NRRI) at the Ohio State University and Argonne National Laboratory. I have also taught graduate and undergraduate level economics courses, including regulatory economics, at Illinois State University and undergraduate economics courses at the Ohio State University, the University of Illinois at Urbana-Champaign and Parkland College.

I am currently on the faculty of the Institute for Public Utilities at Michigan State University where I am an invited lecturer at the Institute's annual Regulatory Studies Program. I have also been an invited lecturer on rate-of-return issues at NARUC and other regulatory and public utility finance conferences around the country. I have testified before numerous state regulatory commissions, as well as before the Federal Energy Regulatory Commission, the Federal Communications Commission and the Iowa and Illinois General Assemblies on issues concerning public utility regulation.

I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A. in Public Utility Economics at the University of Wyoming, and a Ph.D in Economics at the University of Illinois at Urbana-Champaign.

Q. Have you ever testified in North Dakota before?

A. Yes. I testified in Case Nos. PU-400-00-195 and PU-401-00-36 on behalf of Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") and Otter Tail Power Company regarding performance based regulation mechanisms for their electric utility operations in North Dakota.

Q. Please describe your practice at NERA.

A. Since joining NERA in 1999, I have been retained by both public and private interests to provide my expert analysis of numerous public policy issues that face regulators and utilities. My domestic practice consists of advisory work for clients on issues pertaining to regulation and market conditions and providing expert opinion on issues of public policy

toward regulated utilities. My international practice consists of advising governments and utilities on the appropriate course for public policy through the transition from centralized planning toward a more liberalized economy and utility industry. This includes training newly formed regulatory commission staff and commissioners in best practices of regulation. My practice has allowed me to address issues from electric restructuring, firm governance and mergers, rate design and the applications of competitive principles toward regulated utilities. A more detailed description of my academic and professional experience can be found in my curriculum vitae attached to this testimony as Exhibit ___(KAM-1), Schedule 1.

Q. What is the purpose of your testimony?

A. I have been asked by the Company to conduct an independent assessment of the fair and reasonable return on common equity capital employed in the natural gas utility operations of Xcel Energy in North Dakota. In forming my professional opinion on this issue, I have taken into account the need to be fair to ratepayers and the need to attract capital and maintain financial integrity. In order to achieve these goals, the fair rate of return on equity capital must be commensurate with the returns earned by firms with comparable investment risk.

Q. What is your conclusion after your review of the facts and circumstances in this case?

A. As summarized on Exhibit ___(KAM-1), Schedule 2, it is my opinion that a just and reasonable return on common equity of 11.56% should be used in establishing Xcel Energy's gas revenue requirement. This is the mid-point of a range of 11.14% to 11.98% as determined through the use of both a discounted cash flow ("DCF") and a capital asset pricing model ("CAPM") analysis. However, it is my understanding that the Company is requesting that final rates be established using a slightly lower return on common equity of 11.5 percent, the same return on common equity established in the Company's most recent natural gas rate case in 2000 (Case No. PU-400-00-521). The testimony of Mr. Kent Larson supports the Company's request. Mr. Jeffrey Robinson testifies that using the 11.5 percent return on common equity and the Company's test year capital structure results in an overall return of 9.43 percent.

Q. Please describe how your testimony is organized.

A. My testimony is organized as follows. In **Section II**, I discuss the theory and practice of estimating the cost of capital, reviewing the appropriate standards for setting and describing my rational for employing the DCF and CAPM approaches. In **Section III**, I summarize my findings and recommendation

II. COST OF CAPITAL ANALYSIS

A. Regulatory Principles

Q. What is a utility's overall cost of capital?

A. A utility's overall cost of capital is the weighted average cost of capital (WACC). The WACC is the sum of the costs of the components in the capital structure, *i.e*, long term debt, short term debt (if used in a utility's capital structure in the particular regulatory jurisdiction), preferred stock (if any) and common equity, after each component is weighted by its respective proportion of the utility's total capitalization. As I understand, the Company includes short term debt in its test year capital structure, as explained by Mr. Robinson.

Q. What is meant by the term fair rate of return?

A. Any business, whether regulated or unregulated, must be expected to earn enough profit to compensate present investors for the risks incurred by providing capital to the firm if new capital is to be attracted on reasonable terms. If new capital cannot be attracted on reasonable terms, a business will have difficulty providing reliable and adequate service. For a regulated utility, this opportunity to earn a fair return is critical as it has an obligation to serve customers and cannot exit the business. In order to compete with all other entities, including governments that obtain capital via public markets, a utility must have the ability to pay investors their opportunity cost of investing. If a utility cannot meet these requirements, investors will simply put their money in an alternative investment.

Q. Please define the opportunity cost of capital.

A. The opportunity cost of capital is the future compensation that investors expect for taking on the risks associated with a particular investment. This is also referred to as the investor's required return. Investors have many other opportunities or alternative investments to which their capital can be applied, and the opportunity cost of capital alternatives uses to which capital can be put. Therefore, the opportunity cost of capital is influenced by the competition for the limited capital funds between **all** potential users of capital. Since the opportunity cost of capital is an expectation, I cannot directly observe investors' required return; rather, I must estimate it based on observations of the market.

Q. In setting rates, what is the allowed rate of return for a public utility?

A. The allowed rate of return is the overall cost of capital that the Commission authorizes a utility to recover through rates. Note that this is not a guaranteed rate of return; rather it is the level that the utility has an opportunity to recover without the Commission resetting its rates if its costs and sales reflect test year levels. The overall cost of capital (*i.e.*, the authorized rate of return) should be based on an appropriate capital structure and appropriate equity, preferred stock (if any), and debt capital costs.

Q. Why is it necessary to determine an appropriate overall cost of capital for a public utility?

A. Capital costs are similar to any other cost of doing business and must be recoverable through the rates approved by the Commission. Allowing a utility the opportunity to recover its appropriate capital costs will properly balance the interests of ratepayers and investors. If the cost of capital is set too high, ratepayers will be burdened with excessive rates. Conversely, if it is set too low, a utility's financial condition and its ability to provide efficient, safe, adequate, and reliable service will be adversely affected. This will also negatively affect ratepayers through reduced service quality. Therefore, ratepayers' and investors' interests are best served by setting the allowed rate of return on rate base equal to an appropriate overall cost of capital. As discussed above, Mr. Robinson provides testimony describing the Company's test year capital structure and proposed overall cost of capital.

B. Cost of Equity Analysis

1. Overview

Q. What regulatory principles should be followed in determining an appropriate cost of common equity?

A. A utility's allowed rate of return on common equity should be set equal to the utility's appropriate cost of equity. The appropriateness of a utility's cost of equity is dependent upon company-specific factors such as an appropriate capital structure, company-specific risk factors, and the financial condition of the Company. These company-specific factors comprise a utility's business and financial risk. Business risk is a term that refers to the uncertainty of income flows caused by the nature of a firm's business, while financial risk refers to the uncertainty introduced by the method of financing an investment (*e.g.*, debt usually requires fixed payments so having more debt increases a firm's financial risk).[1]

In order to measure the opportunity cost of equity that is applicable to Xcel Energy's regulated natural gas local distribution company ("LDC") operations in North Dakota (which I refer to as the "Target Company"), it is necessary to assemble a group of gas utilities with publicly-traded stock that are representative, on average, of the business and financial risk faced by the Target Company.

Over the years, regulation has established a set of criteria or guidelines consistent with the guidelines set forth by the U.S. Supreme Court in the *Hope*[2] and *Bluefield*[3] cases, which have been more recently affirmed by the Court in *Duquesne.*[4] Essentially, these cases require that utilities be authorized returns that: (1) are comparable to alternative investment opportunities of corresponding risk, (2) permit capital attraction on reasonable terms, and (3) maintain financial integrity.

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[1] Frank K Reilly, *Investment Analysis and Portfolio Management*, 2nd ed (Dryden Press Chicago, 1985), p 14

[2] *Federal Power Commission v Hope Natural Gas Company*, 320 U S 591, 603, (1944)

[3] *Bluefield Water Works & Improvement Co v Public Service Commission of West Virginia (262 U S 679, 1923)*

[4] *Duquesne Light Company v Barasch*, (98 PUR 4th 253 (1989)

To attract capital in the marketplace, a utility must offer to investors an expected return that is commensurate with the returns of alternative investments having similar risks. This traditional standard for a fair and reasonable return was established by the U.S. Supreme Court in its *Hope* decision:

> ...the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks.* That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital.* (Emphasis added.)

This passage from the *Hope* decision is fully consistent with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital. Because the market-based required return is prospective in that it determines the return investors expect when investing in a given investment, the inappropriate use of historical or non-market related data would inhibit the ability to accurately determine the return required by investors.

In the *Bluefield* case, the U.S. Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Furthermore, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fourteenth Amendment.

Thus, investors' required returns create the basis by which the Commission should establish a utility's allowed cost of equity. The market-based cost of common equity, as determined through an analysis of a group of companies that are comparable to Xcel Energy's regulated natural gas LDC operations in North Dakota, should be accepted as the allowed fair rate of return on common equity. As a result, rates will be established based on an approach that is consistent with sound regulatory and financial principles.

Q. Please describe the difficulties associated with cost of equity estimation?

A. Estimating the cost of equity has always been one of the most controversial issues in utility ratemaking. This arises in part because, as noted above, the actual investor requirements are not directly observable. Thus, it is very important to use financial methods, based on the sound application of financial theory, which let the market "do the talking" as much as possible.

For the purposes of calculating the fair return in this case, I will rely on a combination of the DCF model and a CAPM analysis in the cost of equity studies that follow in **Section II** of this testimony. I also consider whether the results of my DCF and CAPM analyses are consistent with the allowed returns on common equity set by other state utility regulators.

Q. What methodology did you employ to determine the cost of common equity?

A. To determine the appropriate cost of common equity, I first identified a peer group of companies similar in risk to the Target Company. Because of the lack of market-based information that is available for the Target Company, I selected my peer group from the publicly-traded natural gas utilities that are followed by Value Line. I performed my cost of equity analysis on this group of companies.

I performed a DCF analysis to directly measure the market-required return. As a check on the DCF model results, I also performed a CAPM analysis. The use of two cost of capital methodologies to derive my estimate of the Target Company's cost of common equity provides added assurance regarding the appropriateness of my results.

2. Comparable Group

Q. Why did you use a group of comparable companies in your cost of equity analysis?

A. The purpose of my testimony is to determine the cost of common equity of the Company's natural gas LDC operations in North Dakota. The Target Company is not publicly traded and therefore it is not possible to analyze directly the opportunity cost of the Target Company. Also, a direct analysis of the Target Company would raise the question of *circularity*: the outcome of a rate case can have a meaningful effect on a regulated utility's

cash flows, which would affect the valuation of the Company's stock, which would affect its cost of equity capital.[5]

Proxy groups of comparable companies are used to estimate indirectly the cost of equity of Xcel Energy's gas operations in North Dakota. The use of a group of companies that are comparable to the Target Company in terms of business and financial risk is consistent with the *Hope* decision and provides a more reliable and objective estimates of the return on equity required by the capital markets. The DCF renders a cost of capital estimate using the results for each company in the proxy group, which is the "population" of companies that are comparable to the Target Company. The results of any one company in the proxy group might seem a bit high and others a bit low, but each of the individual company results provide valid information.

A cost of equity estimate for a group of gas utilities that have comparable risk provides a data source by which to determine a cost of equity estimate for these companies, or any other company that is being analyzed. First, I eliminated three companies that did not pay or had cut their common dividends. Second, I excluded the companies with revenues from regulated operations of less than 80 percent. Third, I eliminated the companies that were involved in mergers. The six firms that comprise my comparable proxy group are shown on Exhibit ___(KAM-1), Schedule 3 and are all of the publicly-traded natural gas LDCs that are followed by Value Line and that:

1. Have not eliminated or reduced their common dividend during the most recent eight quarters. A history of paying a common dividend is necessary for my DCF analysis.

2. Receive 80 percent or more of their revenues from regulated utility operations. Since the Target Company is a regulated gas LDC in North Dakota, this screens out companies that are diversified into non-regulated areas.

3. Have less than $10 billion of equity capital.

[5] Roger Morin explains that "[t]he net result is that the cost of equity depends in part on anticipated regulatory action, since both components of K, yield and growth, are influenced by the regulatory process." *See* Roger A Morin, *Utilities' Cost of Capital* (Arlington, VA: PUR, 1984), pp 143-144

4. Are not involved in a merger. Companies involved in a merger would trade based on the specific terms of the merger agreement and therefore are not appropriate for use here

These companies are appropriate for use in determining the cost of common equity of the Target Company and therefore used in both my DCF and CAPM analyses.

3. DCF Analysis

Q. Please describe the DCF model used in determining the cost of common equity capital.

A. The DCF model provides a conceptually correct and straightforward approach for determining the cost of equity capital. The DCF model is based on the fundamental principle that the value of an asset is equal to the expected cash flows generated by that asset, discounted by the investor-required rate of return. Specifically, the market value of common stock is equal to the present value of the expected stream of future dividends. When using the DCF model, a comprehensive analysis of a utility's business and financial risks is unnecessary because the market's assessment of risk is embodied in the market price of the utility's stock. Furthermore, the DCF model directly establishes a cost of equity capital based on the investors' required rate of return rather than on historical earned returns.

Q. How are stock prices evaluated by investors?

A. Investors generally operate on the principle concept that a stocks price should represent the present value or discounted value of all future dividends that investors expect to receive. In its most general form, a discounted cash flow model captures this in the following formula:

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad (1)$$

Where, P_o is today's stock price; D_1, D_2, etc. are all future dividends and k is the discount rate, or the investor's required rate of return on equity. Equation (1) is simply a routine present value calculation based on the assumption that the stock's price is the present value of all dividends expected to be paid in the future. If I make an additional assumption that

dividends are expected to grow at a constant rate g and further assume that k is strictly greater than g, then equation (1) can be solved for k:

$$k = \frac{D_1}{P_o} + g \qquad (2)$$

This equation is the familiar constant growth DCF model for cost of equity that I will employ in this testimony.

Q. Please describe the annual DCF model.

A. Exhibit ___(KAM-1), Schedule 4 demonstrates that the annual required rate of return on common equity for a firm that pays dividends annually may be determined by solving for K_e in the following equation:

$$K_e = \frac{D_o(1+g)}{P_o} + g \qquad (3)$$

Where:

$K_e \equiv$ the required rate of return on common equity;

$D_o \equiv$ the current annual dividend;

$P_o \equiv$ the current market price; and,

$g \equiv$ the expected annual growth rate in dividends.

Q. Do utilities typically pay dividends on an annual basis?

A. No, they do not. Most utilities pay dividends on a quarterly basis, although dividend increases typically occur no more than once per year.

Q. Is a quarterly DCF model, which reflects quarterly dividend payments and annual, if any, dividend changes, necessary to properly estimate the cost of capital?

A. Yes. The DCF model used should properly reflect known circumstances; otherwise the resulting cost of capital estimate can be skewed.

Q. Have you utilized a quarterly DCF model to determine the required rate of return for the firms in your analysis and if so, why?

A. Yes, I have performed a cost of equity analysis using the quarterly DCF model discussed on Schedule 4 and I have relied on this model in developing my estimate of the Company's cost of common equity. Because all of the companies in my comparable group pay dividends on a quarterly basis, I have used a quarterly DCF model in my analysis.

The quarterly DCF model correctly recognizes the timing of these dividend payments and their value to investors. Therefore, the quarterly DCF model discussed on Schedule 4 is the appropriate model by which to compute the cost of equity for a utility that pays dividends quarterly. Schedule 4 also provides a thorough discussion of the principles that support the use of a quarterly DCF model.

C. DCF Inputs

Q. What are the inputs to the DCF model that you used?

A. The DCF model that I use requires the current market price (P_o), the expected dividend (D_1), and the expected growth rate in dividends (g). The current stock price reflects all of the information available to the market and is necessary to properly embody investor expectations; I use a 30-day average stock price, which reflects current conditions, while not being overly dependent on any one day's stock price results. The expected dividend and its expected growth rate is that used by investors and should be reflective of their expectations in valuing a security. Use of these inputs will produce estimates of the cost of equity that are based on investors' rate of return requirements. The use of historical yields, historical growth rates, or outdated stock prices in the DCF model would yield dubious results given changing industry and market conditions. The stock price and dividend inputs used in my DCF analysis are shown on Exhibit ___(KAM-1), Schedule 5, and Exhibit___(KAM-1), Schedule 6, respectively.

1. Expected Dividend Yield

Q. How did you determine the expected dividend yield for the companies in your group?

A. For each market-traded utility included in my DCF analysis, I calculated a dividend yield based on a 30-day average price, which was the period from September 30, 2004 to November 10, 2004. Exhibit___(KAM-1) Schedule 6 presents the estimated quarterly dividend amount and Exhibit ___(KAM-1) Schedule 7 presents the annual dividend yield (calculated using a quarterly DCF model) for the firms in my six-company group.

Q. What stock price should be used in a DCF analysis?

A. In principle, a current price should be used because it:

(1) Properly reflects current market conditions and the requirements and expectations of investors;

(2) Is more timely and forward-looking than an average stock price in that it incorporates recent events (*e.g.*, economic reports, world events, interest rate movements, etc.) and recent changes in the industry;

(3) Better correlates with the release of analysts' growth rate estimates; and

(4) Is consistent with the Efficient Market Hypothesis (EMH).

Q. Please briefly explain the EMH.

A. The EMH, the cornerstone of modern financial theory, suggests that capital markets are efficient because:

(1) There are a large number of profit-maximizing participants concerned with the analysis and valuation of stocks and who operate independently of each other;

(2) New information regarding stocks comes to the market in a random fashion and the announcements over time are independent from one another;

(3) Investors rapidly adjust stock prices to reflect the effects of new information;

(4) The number of profit maximizing investors is large; and

(5) Price changes are independent and random.

Because of these factors, the EMH suggests that the stock prices that prevail at any point in time should be an unbiased reflection of investors' expectations. Numerous empirical studies of the EMH have been completed; these studies generally support the EMH.[6] To summarize, an efficient market is one in which stock prices adjust rapidly to the infusion of new information, and current stock prices fully reflect all available information, including the risk involved. Because the returns implicit in the market price reflect the risk involved, the expected return is consistent with risk.

Q. Given the above discussion of the EMH, why did you use a 30-day historical average stock price in your analysis?

A. While averaging stock prices over lengthy periods would give equal weight to the oldest observations relative to recent observations and therefore would detract from the DCF model's ability to reflect current conditions and expectations, it is important to ensure that my DCF calculations are not unduly biased by short-term price movements. For that reason, I have determined that a 30-day average stock price, which reflects stock prices from a six-week period, is suitable for use in my DCF analysis. A 30-day average stock price provides many of the benefits of the use of a current stock price while not being overly influenced by short-term fluctuations. The 30-day average stock prices of the six companies in my comparable group are shown on Schedule 5.

2. Growth Rate

Q. Please discuss the growth rate used in the DCF model.

A. A growth rate that reflects investors' expectations is a required input into the DCF model. As a result, investors' expectations are the key element in any DCF analysis. Although the current market price reflects aggregate investor expectations, no method exists to directly measure the market-consensus expected growth rate for a company. Therefore, I have used two approaches to determine the expected growth rate for the proxy group companies.

[6] A survey of this literature can be found in Frank K Reilly, *Investment Analysis and Portfolio Management,* 2nd ed (Chicago The Dryden Press, 1985) at 163-195.

Q. Did you use information found in *The Value Line Investment Survey* in performing your growth rate analysis?

A. Yes, I did. Value Line provides data that can be used to estimate the growth rate. Value Line provide data on historical and projected earnings per share, which I use to calculate the five-year Value Line EPS growth rate, as shown on Exhibit ___ (KAM-1), Schedule 8. To estimate the long-term growth of the utility, projections of future EPS are appropriate. Financial analysts, such as Value Line (an independent financial information service), exert considerable influence over the many investors who do not possess the resources to make their own forecasts. The accuracy of these forecasts, in the sense of whether they turn out to be correct, is not the issue as long as they reflect widely held investor expectations. Schedule 8 summarizes the Value Line EPS growth rate that I calculated.

Q. Could you explain what is meant by a "BR + SV" growth rate?

A. Yes. Growth can be defined as:

The sustainable growth rate for each company is estimated using the following formula:

$$g = B * R + S * V \quad (4)$$

Where:

B	=	expected retention ratio
R	=	expected return on equity
S	=	percent new equity expected
V	=	1 - book to market ratio

Investors expect growth through both retained earnings and the sale of new stock at a premium of book. Thus it is important that the S * V term not be ignored, otherwise the resulting formula will not accurately represent investor expectations. The results of the sustainable growth method are presented on Schedule 8.

Q. What are the appropriate inputs to use in determining the internal growth rate of your gas utility group?

A. Investors realize that, over time, a variety of factors will affect a utility's expected earned return and expected retention ratio. Because investors' long-run expectations of the earned return on common equity and expected retention ratio are not directly observable, estimates must be determined based upon an analysis of both long-term and short-term trends.

The September 17, 2004 edition of *The Value Line Investment Survey* can be used to estimate both the retention ratio (b) and the expected return on equity (r) for the 2007 to 2009 period. The product of these numbers yields an internal growth rate for the firms used in this DCF analysis. Value Line projects a "Percent All Dividends to Net Profits" ratio for the 2007 to 2009 period. One minus this ratio is equal to the retention ratio used as "b" in the "br" calculation. The other necessary input—"r"—is presented by Value Line's as the "Percent Earned Common Equity." Exhibits ___(KAM-1), Schedule 9 and ___(KAM-1), Schedule 10 present the inputs and calculations used in my BR + SV analysis. Schedule 8 presents the results of that analysis for the proxy group.

3. Selling and Issuance Costs

Q. Should utilities be allowed the opportunity to recover reasonable costs associated with issuing equity capital?

A. Yes. Utilities should be allowed the opportunity to recover from ratepayers the reasonable costs of providing service including the reasonable costs of raising equity capital. Reasonable issuance costs, similar to other allowable expenses, should be borne by ratepayers

Q. Should an increment be added to the required return on common equity of the company due to issuance expenses?

A. Yes. Utilities should be allowed the opportunity to recover the reasonable costs of providing service, including the reasonable costs of raising equity capital. If the Target Company requires equity capital, it can obtain it from either its parent (Xcel Energy Inc.),

from minority shareholders (if any), or from an initial public offering. To accurately estimate the cost of equity capital, it is necessary to make an issuance expense adjustment to account for the difference between the cost of the common equity to investors and the proceeds to the Company. As I understand, common equity issuances today would occur at the Xcel Energy Inc. (parent) level. While the cost is incurred indirectly when the Company receives equity capital from its parent rather than the market, there is none-the-less an economic cost associated with these issuance costs that should be borne by ratepayers. Further the equity in the company is a result of prior public offerings made when Northern States Power was publicly traded.

Q. How do you make your issuance and selling expense adjustment?

A. It is proper to include an issuance expense return adjustment for the entire equity component of the capital structure.[7] Therefore, I use the conventional form of the issuance expense adjustment:[8]

$$r = \frac{D_1}{P_0 * (1 - f)} + g \qquad (5)$$

Where

r = required return adjusted for issuance expenses

f = flotation cost percentage

[7] Support for using total common equity appears in Eugene F Brigham, *et al* , "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36

[8] This formula appears in Roger A Morin, *Utilities' Cost of Capital*, (Arlington Virginia Public Utilities Reports, Inc , 1984), 106; and Eugene F Brigham, *et al* , "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), 28-36

For the purpose of choosing an appropriate value for f, the flotation cost percentage, I refer to a publication by Victor Borun and Susan Malley as well as information specific to the Company's public equity issuances.[9] Borun and Malley conclude that total flotation costs for electric utilities are about 5.5 percent. My calculation of the average expense the Company has actually incurred is 5.11 percent as found on Exhibit ___(KAM-1), Schedule 11.

Q. What increment for issuance expenses should be used here?

A. As shown on Schedule 11, I support the use of a 5.31% increment for issuance expenses. To accurately estimate the cost of equity capital, it is necessary to make an issuance expense adjustment to account for the difference between the price to investors and the proceeds to the Company.

D. Summary of Results of DCF Analysis

Q. Based on your DCF analysis, what is the cost of equity of your natural gas utility comparable group?

A. As shown on Schedule 7, the DCF cost of equity for my comparable group is 11.98 percent.

E. CAPM Analysis

Q. How does modern portfolio theory factor into the analysis of the cost of equity?

A. Modern portfolio theory and the CAPM approach have their appeal in that they employ the approach of evaluating assets based on their twin characteristics of risk and return. Moreover, these approaches evaluate assets in terms of their effects on the risk and returns of an investors' entire portfolio. The CAPM approach illustrates this relationship in the security market line.

[9] Victor M Borun and Susan L Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, (February 20, 1986), pp 33-39

Q. Please describe modern portfolio theory.

A. Modern portfolio theory recognizes that investors hold securities in a portfolio.[10] Portfolio theory begins by recognizing that:

1) There is a tradeoff between risk and return and that a rational, risk-averse investor will search for assets that maximize return while minimizing risk, these assets are on the "efficient frontier" shown in part A of Figure 1;

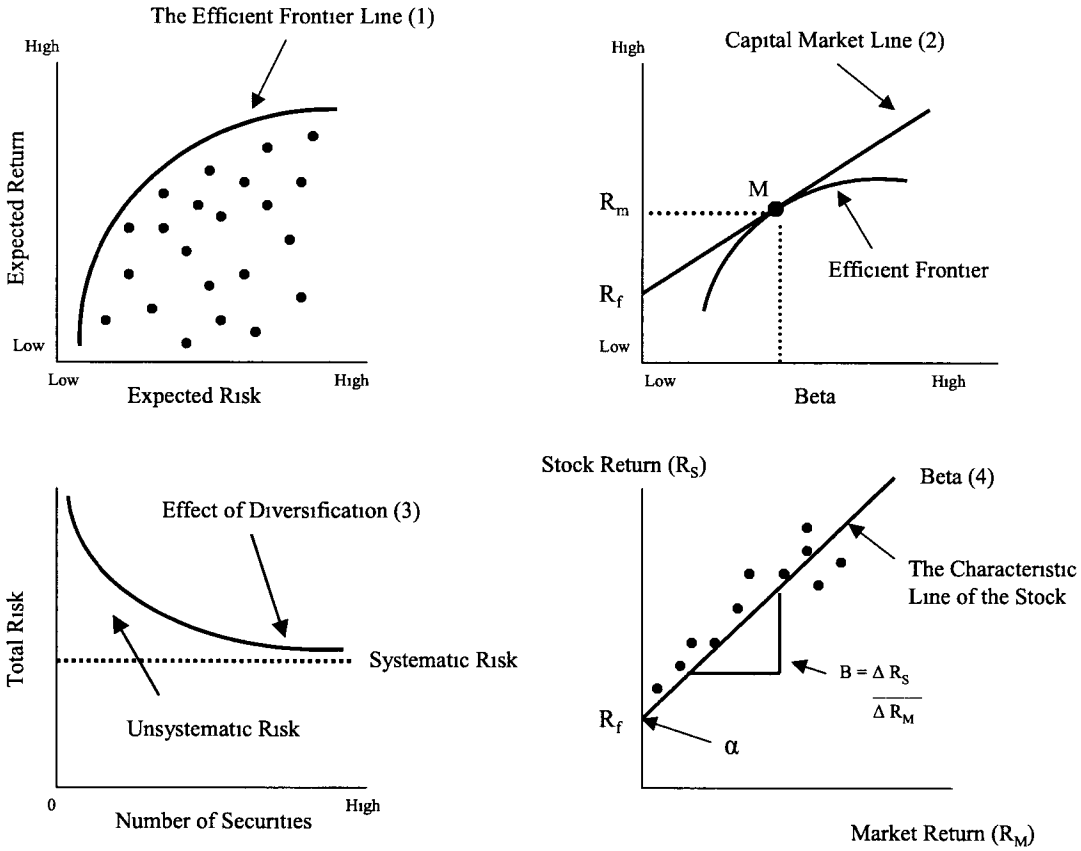
2) If you make the simplifying assumptions that there are two assets to choose from, a "risky" asset and a "risk-less" asset, then the line drawn from the risk-free rate to the efficient frontier, called the "capital market line" are the efficient choices for the investor. The investor can choose the weightings between the risk-free rate and the risky asset, depending on risk preferences;

3) When an investor adds assets that are not highly correlated with the assets in the portfolio, this diversification reduces risk without reducing expected return; thus, for the investor in a diversified portfolio, only those risks that cannot be diversified away are relevant; and

4) CAPM builds on each of these concepts, with the return to the investor equal to the risk-free rate and a risk premium that reflects the risk that a diversified investor cannot avoid (beta) through diversification.

[10] In 1990, three of the originators of modern portfolio theory, Harry M Markowitz, Merton H Miller, and William F Sharpe, shared the Nobel prize in Economics for "their pioneering work in the theory of financial economics " *See* http://nobelprize org/economics/laureates/1990/index html (downloaded November 24, 2004).

1



2 **Figure 1: Modern Portfolio Theory**

3

4 Q. Please describe the CAPM analysis used to determine the cost of equity capital.

5 A. The CAPM is based on the theory that the market's expected rate of return for a given
6 security is equal to the risk-free rate of return plus a risk premium associated with that
7 security. The CAPM is consistent with the belief that investors are risk averse. If an
8 investor has an opportunity to purchase one of two securities with equal expected return, he
9 or she will purchase the security with less risk. Conversely, if an investor has an
10 opportunity to purchase one of two securities with equal risk, he or she will purchase the
11 security with the higher expected return.

12

The Capital Asset Pricing Model can be expressed mathematically as follows:

$$R_j = R_f + \beta_j (R_m - R_f) \qquad (6)$$

Where:

$R_j \equiv$ the required rate of return for stock j;

$R_f \equiv$ the risk-free rate,

$R_m \equiv$ the expected return for the market portfolio; and,

$\beta_j \equiv$ the measure of risk for stock j.

Q. What risk-free rate did you use?

A. In the CAPM model, investors can invest in either a risky asset or a risk-less asset and weights these assets in a portfolio based on risk preferences. The risk-free rate fluctuates with conditions in the capital markets as well as inflation expectations. The risk-free rate represents the interest rate (*i.e.*, return) required by investors to defer current consumption for future consumption.

I use the yield on 30-year Treasury Bonds as of November 5, 2004 as the risk free rate.

Based on the November 5, 2004 *Value Line Selection & Opinion*, the bond equivalent yield on 30-year Treasury Bills stood at 4.97%. This observation was made as of October 28, 2004 and therefore coincides with the other data inputs used in my DCF and CAPM analyses. I used this risk-free rate directly in my CAPM model as shown on Exhibit ___(KAM-1), Schedule 12.

Q. Why have you chosen the yield U.S. treasury bonds as the measure of the risk-free rate in your CAPM analysis?

A. The yields of fixed income securities include premiums for default risk and interest rate risk. Default risk relates to the possibility that the debtor will default on principal or interest payments. U.S. Treasury securities have virtually no default risk because of the Federal government's fiscal and monetary authority.

Common equity return requirements incorporate the expected inflation rates that are expected to prevail over the long run and thus U.S. Treasury Bonds more closely matches the life-span of common equity investments. I have therefore used a risk-free rates (R_f), that is based on the yield of long-term U.S. Treasury Bonds, which incorporates inflation expectations over a long investment horizon.

Q. How did you determine the return on the market portfolio?

A. A return on the market was estimated by conducting a DCF analysis for the firms that comprise the Standard and Poor's Stock Index (i.e., "the S&P 500"). A forward-looking market risk premium can be calculated by subtracting the risk-free rate from the estimated 12.89 percent "top-down" cost of equity capital of the S&P 500. Yahoo! Finance[11] provides a 10.81 percent estimate of the "top-down" estimated five-year earnings growth rate of the S&P 500, and S&P[12] provides a 1.78 percent estimate of the current dividend yield of the S&P 500. Combining these inputs using the standard DCF model provides a forward-looking, top-down DCF cost of common equity for the S&P 500 of 12.89 percent, as shown on Exhibit ___(KAM-1), Schedule 13. This represents the best available estimate of the expected return on the market consistent with the CAPM theory.

Q. What firm-specific estimate of risk did you use in your CAPM analysis?

A. In the CAPM analysis, the market risk premium (denoted in equation (6) as "$(R_m - R_f)$") must be adjusted by a firm-specific measure of risk to derive a firm-specific risk premium. The beta coefficient (beta) is widely recognized by the financial community as a firm-specific measure of risk. Beta measures the sensitivity of an individual stock's return to fluctuations in the market as a whole. For example, a beta of 0.80 indicates that a stock's return tends to rise or fall at 80% of the level of the market's movements. That is, for a

[11] "Yahoo Finance S&P Growth Estimate, Next 5 Years," available at http //biz yahoo com/z/a/v/vz html (downloaded September 20, 2004)

[12] "S&P 500 Statistics," available at http //www2.standardandpoors com/NASApp/cs/ContentServer?pagename=sp/Page/IndicesIndexPg&l=EN&b=4&f=1&s=6&ig=48&i=56&r=1&xcd=500&fd=IndicesMonthEnd_500 (downloaded October 29, 2004)

given level of market volatility, a stock with a beta of 0.80 will be less risky than a stock with a beta of 1.0.

The beta for a security is estimated using the following ordinary least-squares technique:

$$R_{j,t} = \alpha + \beta(R_{m,t}) + \varepsilon_t \qquad (7)$$

Where:

$R_{j,t} \equiv$ the return on security j in period t;

$\alpha \equiv$ the intercept term;

$\beta \equiv$ the measure of risk for stock j;

$R_{m,t} \equiv$ the return on the market portfolio in period t; and,

$\varepsilon_t \equiv$ the error term in period t.

Equation (7) represents a mathematical relationship between earned returns of a particular stock and a market portfolio and identifies a measurement of risk which explains the difference in returns. Beta is that measurement of risk.

The risk measured by beta is known as systematic risk and represents that portion of total risk that cannot be eliminated by holding a well-diversified portfolio. The CAPM and modern portfolio theory submit that investors are not rewarded for risk that can be eliminated through diversification (*i.e.*, non-systematic risk). Therefore, investors price only systematic risk in the market place.

I use beta estimates published by Value Line for each firm in my gas utility group. The published beta estimates for each of these firms are included within Exhibit ___(KAM-1), Schedule 12.

Value Line's beta is derived from a regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the New York Stock Exchange Composite Index over a period of five years. That is, Value Line utilizes 260 observations of weekly stock price and index data.

Q. Using the CAPM, what is your estimate of the cost of common equity?

A. My CAPM analysis indicates that the cost of common equity for the proxy group is 11.14 percent. My calculations are shown on Schedule 12.

III. COST OF EQUITY RECOMMENDATION

Q. What is the cost of equity for the Company?

A. Based on my entire analysis, I believe that the Company's cost of equity is within the range of 11.14% to 11.98%. I recommend that the midpoint of that range, **11.56%**, be established as the Company's allowed fair rate of return on common equity.

However, as described by Mr. Larson, the Company is voluntarily requesting that its North Dakota natural gas rates be calculated using a return on common equity of 11.5 percent, slightly lower than my recommended cost of equity, and the same return on common equity used to establish final natural gas rates in the Company's 2000 gas rate case (Case No. PU-400-00-521). In my opinion, the Company's decision to request that rates be determined using the slightly lower 11.5 percent return on common equity is reasonable.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

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STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of Northern States Power Company d/b/a Xcel Energy - Notice of Change in Rates For Natural Gas Service	))))	Case No. PU-400-04-578

AFFIDAVIT OF

KARL A. MCDERMOTT, PH.D

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Karl A McDermott

Karl A. McDermott

Subscribed and sworn to before me, this 30 day of November, 2004.

Carolyn A Johnson

Notary Public

OFFICIAL SEAL
CAROLYN A. JOHNSON
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES 8/15/07
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n/e/r/a
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Exhibit ___KAM-1, Schedule 1

KARL A. MCDERMOTT

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Dr. Karl McDermott is a Vice President with National Economic Research Associates, specializing in public utility regulation. Since Dr. McDermott came to NERA he has directed and participated in numerous projects in both the energy and telecommunications areas. His main focus has been the development of performance-based regulation mechanisms and advising clients on strategic regulatory options. Recent projects include evaluating and developing performance-based regulation plans and strategic regulatory options for Commonwealth Edison Company, Detroit Edison Company, Michigan Consolidated Gas, Wisconsin Electric Power Company, Xcel Energy, Otter Tail Power, Peoples Energy, Louisville Gas and Electric and PowerGen along with MidAmerican Energy In addition, Dr. McDermott also advises clients on competitive electric and gas markets including regulatory policy, generation location decisions, unbundling, tariff design and corporate reorganization. Recent projects include a examination of essential facilities debate for the Edison Electric Institute, tariff design and competitive electric generation sitting for Southern California Gas Company and Southern Energy, and a review of unbundling of metering and billing for Commonwealth Edison Company. Dr. McDermott has testified before numerous state regulatory commissions and legislatures along with the FCC and FERC.

Prior to arriving at NERA, Dr. McDermott served as Commissioner on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. He has also assisted the country of Poland since 1994 with their efforts to privatize and restructure their electric supply industry. As a Commissioner, Dr. McDermott also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring.

During the six years that he served as Commissioner he has had an opportunity to evaluate alternative regulation proposals and the economic and social impacts of a number of new policies presented to the Commission. As a Commissioner, Dr. McDermott initiated the Commission's investigation into the alternative restructuring options and has made a number of presentations on restructuring issues.

Dr. McDermott received a B.A. in Economics from Indiana University of Pennsylvania, a M.A. in Public Utility Economics at the University of Wyoming, and a Ph.D. in Economics from the University of Illinois at Urbana-Champaign.

EDUCATION

Ph D 1990, Economics, University of Illinois at Urbana-Champaign
M A. 1978, Public Utility Economics, University of Wyoming
B.A. 1976, Economics, Indiana University of Pennsylvania

Dissertation Topic: The Monetary Theory of Production of John Maynard Keynes

EMPLOYMENT

1999- NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
Vice President.

Directs projects in the energy and telecommunications fields in NERA's energy and telecommunications practices. Focuses on designing and reviewing performance-based regulation mechanisms and providing strategic regulatory advice to both international and domestic clients. Also provides advice on competitive issues facing regulated firms including regulatory policy, unbundling, corporate structure and tariff design. Representative work includes

- Evaluation and design of performance based-regulation Clients include:
  - ◊ Detroit Edison Company (Bundled electricity service)
  - ◊ Michigan Consolidated Gas (Gas distribution)
  - ◊ NICOR Gas (Gas procurement)
  - ◊ Otter Tail Power (Bundled electricity service)
  - ◊ Xcel Energy (Bundled electricity service)
- Evaluation of damages from coal-fired power plant explosion for Kansas City Power and Light (Hawthorn 5 unit).
- Evaluation of prudence of certain distribution investments and O&M costs for Commonwealth Edison Company.
- Evaluation of POLR responsibility in state of Illinois for Commonwealth Edison.
- Evaluation of market structure options and development of tariff model for Macedonian electric sector
- Evaluation of future options for the reform of the Albanian electric sector.
- Evaluation of electric industry structure and proper public policy toward utilities building power plants.
- Estimation of potential energy efficiency gains for Wisconsin Electric Power Company (WEPCO) and Wisconsin Public Service Corporation in support of power plant construction.

- Evaluation of tariff options for Otter Tail Power Company.
- Evaluation of options for unbundled distribution rates and policies toward small-use customer choice for Illinois Power.
- Review of gas rate design for peaking service and evaluated electric generation site decisions in California for Southern California Gas Company.

1998-1999 MCDERMOTT ASSOCIATES
President.

Directed projects in the energy and telecommunications fields focusing on performance-base regulation, electric industry restructuring and competition policy issues.

1992-1998 ILLINOIS COMMERCE COMMISSION
Commissioner.
Domestic·
Served as Chairman of both the Telecommunications Policy Committee and Electricity Policy Committee. Served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources and Environment Committee as the Chairman of its environmental subcommittee. While at the Commission, reviewed and voted on Illinois Bell Price-Cap plan, Peoples Gas PBR and MidAmerican Electric PBR. Made over one-hundred presentations and speeches on telecommunications, electricity, and natural gas industry topics. Served on the President's Global Climate Change Task Force, the Federal Energy Regulatory Commission's Pipeline Competition Task Force, and as a member of the Harvard Electric Policy Group.

International:

In addition to regular Commission duties, served as part of the United States Energy Association and USAID educational effort in Eastern Europe. Lectured in Argentina, the Czech Republic, Latvia, Poland, Romania, Russia, and Slovakia. Participated in two joint USEA/USAID and World Bank seminars in Vienna providing advanced regulatory training. In addition, the Illinois Commission has hosted visits with the above-listed countries as well as Bulgaria, Lithuania, and Estonia.

PROFESSIONAL ACTIVITIES

2001- *Faculty*, Institute for Public Utilities, Michigan State University.
Invited lecturer at Regulatory Studies Program ("Camp NARUC") held in East Lansing, Michigan. Lecture topics include performance-based regulation, rate-of-return regulation, infrastructure regulation for developing countries, and gas wholesale markets.

1985-1998 *Chairman of the Board*, Center for Regulatory Studies, Inc.

1985-1992 *Presıdent*, Center for Regulatory Studıes, Inc.
One of three cofounders of the Center. Involved in fundraısing, organizatıon, and program development. Focused on the development of statewıde energy plannıng options for the State of Illinoıs, the introduction of competition ınto the natural gas market, envıronmental ıssues in Illınois, and competıtion ın the Illinoıs telecommunications market. Conducted research on the use of competitıve bıddıng and avoıded-cost pricıng mechanısms to acquire electrıcity supplıes, the role of demand-sıde management in electrıcity supply planning, and the use of incentıve mechanısms and the role of ıncentive regulation in our current regulatory environment.

1988-1992 *Research Scıentıst*, Argonne National Laboratory

Served as an economic advisor to the office of Fossil Energy at DOE. Investigated possible ways to promote development of ınnovative emission control technologıes in the electric utılity industry as part of the Presidential Task Force on Regulatory Relief dırected by Vice Presıdent Bush. Involved in wrıting a chapter in the State of Scıence and Technology Report No. 25 of the National Acid Precıpitation Assessment Program (NAPAP) concerning the use of tradable emission permıts to control acid rain. Performed work on incentive mechanısms to promote clean coal technology and the trading of greenhouse gas emıssions.

Performed research on the nature of indıvidual's rısk perceptıon regarding nuclear waste deposits on behalf of the office of Radioactıve Civilian Waste Management at the Department of Energy.

1988-1990 *President Elect and President*, Illinoıs Economıc Associatıon
Organized the 1989 Illinois Economic Association annual meeting and presıded over the meetings.

1989- *Instructor*, NARUC Introductory Regulatory Traınıng Program
Instructed new publıc utılity commission employees from varıous state commissions on the basıc economic ıssues confrontıng regulators.

1986-1992 *Lecturer in Economics*, Department of Economics, Illinoıs State Unıversity
Taught both graduate and undergraduate publıc utılity courses, Money and Bankıng, as well as introductory courses.

1984-1991 *Instructor ın Economıcs*, Parkland Community College, Champaıgn, Illinois
Taught both Prıncıples of Economics I and II, with a typical course load of two sectıons of 35-40 students per class.

1984-1986 *Teachıng Assıstant*, Unıversıty of Illınoıs, Champaıgn, Illinoıs

Taught both Principles of Economics and Introduction to Econometrics. In the spring semester of 1985, was the supervisory assistant in charge of coordinating the Economics 101 assistance for Professor Fred Gotthiel.

1982-1988 Graduate School, University of Illinois, Champaign, Illinois
Completed all coursework towards Ph.D. and defended dissertation on 6/12/88. Fields of specialization were: Monetary Theory and Policy, Macroeconomic Theory, and the History of Economic Thought.

1983-1985 *Consultant*, Select Joint Subcommittee on Regulatory Reform, Illinois Legislature
Investigated the effects of the AT&T divestiture and FCC decisions upon Illinois telephone utilities and assisted in identifying issues that require legislative action. Presentation of issue reports to the telecommunications subcommittee and served on the local exchange subgroup in developing recommendations for a new Illinois Public Utilities Act.

1980-1982 *Consultant*, Governor's Sunset Task Force on Utility Regulatory Reform, Department of Energy and Natural Resources
Delivered both written and oral reports on the issues of power plant certification, monitoring of construction costs, and allocation of power plant cancellation costs.

1980-1983 *Economic Analyst III*, Policy Analysis and Research Division,
Illinois Commerce Commission

Conducted research investigating the development and use of incentive mechanisms in utility regulation. Prepared and presented testimony on the use of incentive mechanisms in power plant construction.

Conducted research and assisted in developing testimony on the cost of service for electric generation to meet PURPA requirements.

Assisted in the development of proposals for PURPA innovative rates projects on productivity and time-of-use pricing; cost-benefit analysis. Assisted in the managing of consultants conducting the TOD cost-benefit study. Prepared and presented testimony on the time-of-day pricing standards to meet the PURPA requirements.

Prepared and presented testimony regarding the use of q-ratios in determining rates-of-return for Illinois Bell Telephone Company and testimony regarding appropriate cost and pricing methodology and philosophy for Illinois Bell Telephone Company.

Assisted in the investigation of capacity expansion, lifeline rates, efficiency measurement, and impact of deregulation in electric generation, water rate design; and investigated the impact of investment tax credit changes on utilities.

1978-1979 *Senior Research Associate*, National Regulatory Research Institute
Ohio State University
Conducted research in the areas of telecommunication licensee contract fees and cost of service, the effects of budget billing plans on utilities and consumers, and methods of monitoring fuel adjustment clauses.

Assisted in research regarding marginal and average cost pricing, time-of-use pricing, power plant productivity, and the examination of cost and price differences of Ohio municipal gas rates.

Assisted in the management of consultant subcontractors as well as supervising the presentation of cost and load research seminars.

9/79-12/79 *Lecturer in Economics*, Department of Economics, Ohio State University
Taught Macro Economic Principles to a class of approximately 100 students.

1977-1978 *Cost Analyst*, Action Computing, Laramie, Wyoming
Developed cost data for competitive pricing of bids for the provision of computer services provided by Action Computing.

1976-1977 *Graduate Research Assistant*, University of Wyoming, Laramie, Wyoming
Assisted professors in conducting research and teaching of Principles of Economics, while completing a Masters degree in Economics with specialization in Public Utility Economics and Industrial Organization Theory.

AWARDS

1986 Alpha Lambda Delta Outstanding Teacher of Freshman Award
at the University of Illinois

1983 Thrift Prize at the University of Illinois for the paper entitled *"The Allocation of Savings: An Investigation of Portfolio Composition of Chicago Households"*

PROFESSIONAL SOCIETY ACTIVITIES

Alpha Lambda Delta Honorary Society
American Economic Association
Transportation Public Utilities Group of American Economic Association
Illinois Economic Association

PUBLICATIONS

"The Anatomy of Institutional and Organizational Failure," in *Obtaining the Best from Regulation and Competition,* M Crew and M Spiegel (eds.), Kluwer Academic Publishers, London, UK, 2005, pp. 65-92. (with Carl Peterson)

"Performance-Based-Rate Upward Trend to Continue," in *Natural Gas and Electricity,* 20(6), 2004 (with Carl Peterson)

"Is There a Rational Path to Salvaging Competition?" *The Electricity Journal,* 15(2), 2002, pp. 15-30. (with Carl Peterson)

"Further State Electric Deregulation can be Guided by Gas Experience," in *Natural Gas and Electric Power Industries Analysis,* R E Willett (ed.), Financial Communications Company, Houston, TX, 2002, pp 343-372. (with Carl Peterson)

"The Essential Role of Earnings Sharing in the Design of Successful Performance-base Regulation Programs," in *Electricity Pricing in Transition,* A. Faruqui and K. Eakin (eds), Kluwer Academic Publishers, London, UK, 2002, pp. 315-328. (with Carl Peterson)

"Critical Issues in Consumer States Include Unbundling and Performance-based Regulation," in *Natural Gas Industry Analysis*, R.E Willett (ed.), Financial Communications Company, Houston, 2000, 321-343.

"Are Residential Local Exchange Rates Too Low? Drivers to Competition in the Local Exchange Market and the Impact of Inefficient Prices,", in *Expanding Competition in Regulated Industries,* M. Crew (ed.), Kluwer Academic Publishers, Boston/Dordrecht/London, 2000, 149-168. (with A. Ros)

Essential Facilities, Economic Efficiency, and a Mandate to Share: A Policy Premier, Edison Electric Institute, January 2000. (with K. Gordon, W. Taylor and A. Ros)

"Pipeline Regulation Must go to One Extreme or Another," *Natural Gas*, 15(9), April, 1999.

"Is There a Rational Path to Implementing Competition?" *The Electricity Journal*, 9(1), Jan-Feb 1996.

"Changing Regulatory Incentives," in *Reinventing Electric Utility Regulation,* G. Enholm and J. Robert Malko (Eds.), Public Utility Reports, Inc. Vienna, VA 1995.

"The Evolution of the "Investment Systems:" Keynes' Theory of Employment and Money Revisited." *Review of Social Economy,* 51(1), Spring 1993.

Discussant. "The Urban Ozone Abatement Problem," in *Cost Effective Control of Urban Smog.* R Kosobud, W. Testa, and D. Hansan (Eds.) Federal Reserve Bank of Chicago. November 1993.

"Strategic Use of Incentive Mechanisms as a Regulatory Policy Tool." *The Electricity Journal.* 5(10), December 1992.

"Electric Utilities: Control Cost Reducing Methods," Chapter 7 in *Technologies and Other Measures for Controlling Emissions: Performance, Costs and Applicability,* David South (ed.). National Acid Precipitation Assessment Program, State-of-Science/Technology Report, 25 January 1990.

"The Quantity Theory of Money of J. M. Keynes: From the Indian Currency to the General Theory" in *Perspectives on the History of Economics Thought.* D., Walker (ed.), Edward Edgar Publishing Co., Brookfield, VT, 1989. (with Christopher Marme)

Computer Assisted Regulatory Analysis and Its Potential Application to the Colorado Public Utilities Commission. The National Regulatory Research Institute, 1979. (with M. S. Gerber)

Towards an Analysıs of Telephone Lıcense Contracts and Measured Rates. The Natıonal Regulatory Research Instıtute, 1979. (wıth A. G. Buckalew, and D. Z Czamanski)

Budget Billıng Plans for Electrıc and Gas Utılıtıes. An Analysıs and Some Recommendatıons for Change. The Natıonal Regulatory Research Instıtute, 1979. (with J-M Guldman, and C Odle)

PUBLICATIONS: CONFERENCE PAPERS

The Anatomy of Instıtutıonal and Organızatıonal Faılure Economıc Reform and the Search for Instıtutıonal Equılıbrıum ın Regulated Network Industrıes, Prelımınary Draft presented at Research Semınar on Publıc Utılıtıes, Center for Research ın Regulated Industrıes, Rutgers Unıversıty, October 2003. (wıth Carl Peterson)

The Effıcıency of the Ineffıcıent Fırm Standard ın Settıng Network Access Charges . Prepared for 20th Annual Advanced Workshop ın Regulatıon and Competıtıon, Rutgers Unıversıty, May 25, 2001. (wıth Carl Peterson)

Desıgnıng the New Regulatory Compact. The Role of Market Processes ın the Desıgn of Dynamıc Incentıves. Presented at *Incentıve Regulatıon. Makıng ıt Work,* Advanced Workshop in Regulatıon and Competıtıon, Rutgers Unıversıty, January 19, 2001. (wıth Carl Peterson)

The Use of Nontradıtıonal Unıversal Servıce Programs ın a Competıtıve Local Exchange Market. Presented at the Natıonal Associatıon of Regulatory Commıssioners Biennıal Conference, 1996 (with Cındı Schieber)

Incentıve Mechanısms as a Strategıc Optıon for Acıd Rain Complıance wıth D. W. South, and K.A. Baıley. Presented to the Future of Incentıve Regulatıon ın the Electric Utılıty Industry, November 1991

Role of Emıssıon Allowances ın Utılıty Complıance Decısions with D. W. South, and K. A. Bailey. Presented at the Eighth Annual Internatıonal Pittsburgh Coal Conference, October 1991.

Clean Coal Technology and Emıssions Tradıng. Is There a Future for Hıgh Sulfur Coal Under the Clean Aır Act Amendments of 1990? With K A. Baıley, and D.W. South. P. R Dugan, D. R. Quıgley, Y. A. Attıa (eds.), Processıng and Utilizatıon of Hıgh Sulfur Coals IV, proceedings of the Fourth Internatıonal Conference on Processing and Utılızatıon of Hıgh Sulfur Coals, Idaho Falls, ID., sponsored by the U.S. Department of Energy, et al., Elsevеır Science Publıshing Co. Inc., New York, NY.

Incentıve Mechanısms as a Strategıc Option in the Design of Regulatory Polıcıes wıth D. W. South. Presented at National Associatıon of Regulatory Utılity Commıssioners, Committee on Electrıcity, Subcommittee on Strategıc Issues, San Francısco, July 1991.

Achıevıng Efficiency Through Emıssions Tradıng: Paradoxes, Mısconceptıons and Market Performance with D W. South. Presented at National Association of Regulatory Utility

Commissioners, Committee on Electricity, Subcommittee on Environment and Efficiency, San Francisco, July 1991.

To Mitigate or Not To Mitigate: Regulatory Treatment of Emissions Trading Decisions and Its Effect on Marketplace Incentives with D. W. South. Presented at 84th Annual Meeting and Exhibition, Air and Waste Management Association, Vancouver, British Columbia, June 1991.

Regulatory Incentives A Means to Accelerate Clean Coal Technology Adoption for Acid Rain Compliance with D. W South. Presented at Compliance and Emissions Trading Strategies: Facing Acid Rain Tradeoffs, Center for Regulatory Studies, Chicago, IL, June 1991.

Implementing Emissions Trading: Regulatory and Compliance Planning Issues with D. W. South Presented at the Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990: Midwestern State Public Utility Commission Issues, National Regulatory Research Institute, Chicago, IL, May 1991).

Clean Coal Technology and Acid Rain Compliance· An Examination of Alternative Incentive Proposals with D. W South. Presented at the American Power Conference, Chicago, IL., April 1991).

Emissions Trading: Implications for Regulatory Policy with D. W South. Presented at the 20th Annual Meeting of the Illinois Economic Association, Chicago, IL, October 1990).

The Future of Clean Coal Technology An Evaluation of the Proposed CCT Incentives in S. 1630 with D. W. South. Presented at the 20th Annual Meeting of the Illinois Economic Association, Chicago, IL, October 1990).

The Future of Clean Coal Technology: An Evaluation of the Proposed Incentives in S 1630 with D. W South. Presented at the Seventh Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 1990).

The Future of Clean Coal Technology: An Evaluation of the Proposed Incentives in S. 1630 with D. W. South Presented at the Seventh NARUC Biennial Regulatory Information Conference, Columbus, OH, September 1990

Emissions Trading· Implications for Regulatory Policy with D. W. South. Presented at the Seventh NARUC Biennial Regulatory Information Conference, Columbus, OH, September 1990.

Alternatives to Rate of Return Regulation in the Telephone Industry A Survey of the New Incentive Mechanism Proposals. Illinois Economic Association, October 1988

Market Structures in the Local Communication Market: Fact and Fiction. Presented at the Intra-MSA Telecommunication Conference, September 1988.

The Quantity Theory of Money of J. M. Keynes From the Tract to the General Theory with Christopher Marme. Proceedings of the 14th Annual Meeting of the History of Economics Society, June 1987

Competitive Pricing and the Local Telephone Service Market: Some Problems of Balancing Equity and Efficiency. Illinois Economic Association, October 1986.

The Impact of Self-Selective Tariffs in Telecommunications Markets The Design of an Experiment with M. J. Morey, and K. Costello. Proceedings of the Fifth NARUC Biennial Regulatory Conference, September 1986.

"An Incentive Plan to Control Power Plant Construction Costs," Third NARUC Biennial Information Conference, September 1982.

The Measurement of Efficiency and the Application of Incentives to Regulated Industries with K. Costello Proceedings of the Second NARUC Biennial Regulatory Information Conference, September 1980.

PUBLICATIONS: REPORTS

Summary of Finding and User Guide: Tariff Model for the Macedonian Electric Sector, prepared for the Ministry of Economy, Republic of Macedonia, under contract with United States Agency for International Development, November 2003. (with Carl Peterson and Ralph Zarumba, report is currently being reviewed and is proprietary).

Distributed Resource Investment in Albania: Regulatory Options for Introducing Commercial Incentives and Promoting Solutions to Meeting Electricity Demand, white paper prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, January 2003. (with Carl Peterson).

Restructuring Options for the Electric Sector in Macedonian, Report 1 and 2; prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, 2002 , (with Carl Peterson and Ralph Zarumba, report is proprietary).

Introducing Competition into the Albanian Electric Sector, white paper prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, 2001. (with Carl Peterson)

Examination of Incentive Mechanisms for Innovative Technologies Applicable to Utility and Nonutility Power Generators, Environmental Assessment and Information Sciences Division, Argonne National Laboratory, publication ANL/EAIS/TM-2,, August 1993.

Avoided Cost Pricing: Theoretical Issues and Problems in Estimation. Prepared for the Illinois Department of Energy and Natural Resources, June 1990

Least-Cost Planning in the Natural Gas Industry· An Overview of the Issues. Prepared for the Illinois Department of Energy and Natural Resources, December 1989.

Equity Issues in a Least-Cost Planning Environment. Prepared for the Illinois Department of Energy and Natural Resources, October 1989.

An Analysis of Prudency Evaluation Within a Least-Cost Planning Framework The Case of Natural Gas Planning. Prepared for the Illinois Department of Energy and Natural Resources, October 1989

Consumer Choice Under Risk and Uncertainty: The Role of Risk Perceptions as a Causal Factor in Consumer Decisionmaking. Prepared for the Energy and Environmental Systems Division, Argonne National Laboratory for U.S. DOE Office of Civilian Radioactive Waste Management, April 1989.

The Effects of Alternative Definitions of the Obligation to Serve on the Least-Cost Plans of Local Gas Distribution Companies. A Report for the Northern Illinois Alliance to Support Least-Cost Utility Planning, February 1989.

A Complete and Economic Study on Proposed IPCB Regulation R89-9. with J L. Carlson, M. J. Morey, R. C Hemphill, and W. Mikucki *Waste Prohibitions* Prepared for the Illinois Department of Energy and Natural Resources.

The Role of Prices and the Pricing System Within the Regulatory Process. Prepared for the Illinois Department of Energy and Natural Resources, October 1986.

An Evaluation of the Minimization of Total Regional Requirements as an Objective in State-Wide Utility Planning Process. For the Illinois Department of Energy and Natural Resources, November 1986.

The Economic Incentives Provided by Section 9-215, Excess Capacity Rule of Proposed Illinois Public Utility Act A Memorandum to the Joint Committee, June 1985.

An Analysis of the Issue of Cross-Subsidization in the Local Telephone Market Prepared for the Joint Committee on Public Utility Regulation, May 1985.

A Survey of State Regulatory Actions and Legislative Developments Resulting from the Divestiture of AT&T. Prepared for the Joint Committee on Public Utility Regulations, Illinois State Legislature, March 1985.

A Memorandum to the Telecommunications Policy Working Group on the Concepts of Competing, Competition and Market Structure, September 1984.

The Evolution of Competition in the Telephone Industry and the Critical Issues Facing the Illinois Legislature on the Deregulation of Telephone Service. Prepared for the Select Joint Subcommittee on Regulatory Reform, July 1984.

The Review of Existing Power Plant Certificates, Monitoring of Power Plant Costs and the Allocation of Power Plant Cancellation Costs. Presented to the Sunset Task Force on Utility Regulatory Reform, January 1984.

Utility Efficiency Report Subtask IX - Final Report in Incentive Mechanisms Prepared for the Illinois Commerce Commission, May 1981.

Utility Efficiency Report Subtask IV - Evaluation and Choice of Incentive Mechanisms. Illinois Commerce Commission for the U.S. Department of Energy, July 1980.

Utility Efficiency Report Subtask II - Review of Existing Incentive Mechanisms Illinois Commerce Commission for the U S. Department of Energy, March 1980

Estimating Fuel Prices, a Memorandum to the Virginia State Corporation Commission with K. Kelly, National Regulatory Research Institute, 1979.

Summary of Regulatory Commission Activities on Power Plant Productivity. The National Regulatory Research Institute draft report for the U S. Department of Energy, 1979.

UNPUBLISHED PAPERS

PBR in Gas Distribution, Working Paper, National Economic Research Associates, Inc, Chicago, IL, November 2003. (with Carl Peterson)

Electric Industry Evolution in Eastern Europe After 1990, Working Paper, National Economic Research Associates, Inc, Chicago, IL, November 2002. (with Carl Peterson)

Designing the New Regulatory Contract: Using the Market Process to Design Regulatory Mechanisms, Draft Paper, National Economic Research Associates, Inc,, Chicago, IL, November 2000.

Decentralization vs. Coordination. An Examination of the Options for Deregulating the Electric Supply Industry. June 1985

Applied Fairness Theory: The Case of Allocating Canceled Power Plant Costs., October 1983

Towards Developing a Framework for Evaluating Incentive Mechanisms, Performance Measures and Institutional Choice in Deregulation., August 1981

An Overview of the Theories of Regulation and Pricing Policies for Regulated Industries. The National Regulatory Institute. 1979

A Critique of the Averch-Johnson Bias and a Test of Some Alternative Hypotheses. Master Thesis submitted to the Graduate School of the University of Wyoming. , July 1978

PRESENTATIONS

Performance-based Regulation and the Stand-Along Distribution System, Distribution System Planning, Maintenance and Reliability Conference, Denver, November 2000.

The Moral Obligation to Regulate Intelligently. Presented to the NARUC Telecommunications Staff Sub-Committee at the 112th Annual NARUC Convention, San Diego, November 2000.

Concepts of Utility Regulation for Developing Countries, 42nd Annual Regulatory Studies Program, Institute for Public Utilities, Michigan State University, August 2000.

The Essential Role of Earnings Sharing in the Design of Successful Performance-Based Regulation, Presented at EPRI's International Energy Pricing Conference, Washington, D.C. July 2000.

Transmission Pricing Distance-sensitive, but not Pancaked. Presented at the EEI Transmission Pricing Conference, Washington, D.C., July 2000.

Telecommunications Rate Rebalancing. Presented to the NARUC Telecommunications Staff Sub-Committee at the NARUC Convention, Los Angeles, July 2000

Coal, Energy and Clean Air Challenges and Opportunities, facilitator, Illinois Department of Economic Development and Community Affairs and the Illinois Environmental Agency, Decatur, Illinois, July 2000.

PBR Strategy Seminar, Illinois Power Company, April 2000.

Strategic Application of Distributed Resources, Illinois Power Company, April 2000.

PBR Strategy Seminar, with Jeff Makholm, Georgia Power Company, April 2000

Codes of Conduct for The Electric Industry, presented on behalf of the Edison Electric Institute at the Commissioner Liaison Committee meeting, NARUC Winter Meeting, Washington, D.C., March 2000.

Mergers and Acquisitions Assessing the Trends in the Electric and Gas Industries, Presentation to the Midwest Energy Bar Association, Kansas City, March, 2000

Telecommunications Industry in the Aftermath of TA96 Creating a Consistent Regulatory Framework amidst the Complexities of the Contemporary Marketplace, Presented to the NARUC Telecommunications Staff Sub-Committee at the NARUC Annual Convention, San Antonio, November 1999.

Cost Allocation for Affiliate Transactions, presented on behalf of the Edison Electric Institute at the Joint Meeting of the Finance and Technology, Gas and Electric Committees, NARUC Summer Meeting, San Francisco, July 1999.

Avoided Cost Calculation Methodologies, presentation to Energy Sector Representatives of Romania and Bulgaria, Bucharest, Romania, Fall 1999.

RTO and ISOs: Restructuring Options, presentation to Energy Sector Representatives of Romania and Bulgaria, Sinaia, Romania,, Summer 1999.

Convergence. The Utility of the Future, Presented to Wisconsin Electric Company and Wisconsin Gas merger transition team., 1999

A Conflict of Paradigms: The Future Role of State Regulation of the Natural Gas Industry. Presented to the Midwest Gas Association, November 6, 1991

Exit and Entry Who Will Bear the Risk in a Competitive Natural Gas Industry Presented at the conference "At the Crossroads: Restructuring the Natural Gas Industry," held by the Center for Regulatory Studies, October 1991.

"To Serve Man" - The Golden Rule or a Visit to the Twilight Zone: How to Reconcile the Obligation to Serve with Competitive Market Forces Presented to the Gas Policy Committee of the Illinois Commerce Commission, April 16, 1991.

Regulatory Treatment of Emissions Trading Decisions and Their Effect on Marketplace Incentives with D. W. South Presented at the Notice of Inquiry Public Hearing, Illinois Commerce Commission, March 1991.

The National Energy Strategy: Impacts on the Farm Sector. Presented to the Illinois Farm Bureau Leadership Conference, February 1991.

Emissions Trading in the CAAA of 1990 Regulatory, Compliance Planning and Implementation Issues with D. W South Presented to the Illinois Commerce Commission, January 1991.

Obligations to Serve and Competition in the Natural Gas Industry. Luncheon presentation at the conference "Assessing the Competitiveness of the Natural Gas Industry," held by the Center for Regulatory Studies, October 1990.

Pricing in an Age of Opportunism: The Cost of Being a Provider of Last Resort Presented at the conference "Natural Gas Supply Planning: The Implications for Planning Pricing and Competition," held by the Center for Regulatory Studies, March 1990.

Public Utility Issues: Long and Short-Term Impacts. Presented to the Illinois Farm Bureau Leadership Conference, February 1990.

Uncertainty in the Least-Cost Planning Process: The Case of Natural Gas Presented at the conference "Issues in Least Cost Planning in the Natural Gas Industry," held by the Center for Regulatory Studies, December 21, 1989.

While at the Illinois Commerce Commission, Dr. McDermott gave over one-hundred presentations on a variety of topics in the telecommunications, electricity and natural gas industries

TESTIMONY

Oregon Public Utility Commission, Case No. UM 1121, Direct Testimony on behalf of Oregon Electric Utility Company, concerning the acquisition of Portland General Electric, Spring 2004.

Michigan Public Service Commission, Case No. U-13898, Direct Testimony on behalf of Michigan Consolidated Gas Company concerning the application of performance-based regulation, Fall 2003.

Michigan Public Service Commission, Case No. U-13808, Direct Testimony on behalf of Detroit Edison Company concerning the application of performance-based regulation. Fall 2003.

Circuit court of Jackson County Missouri, Kansas City Power and Light Company v Bibb Associates, et. al. Case No. 01CV207987. Expert report and testimony on behalf of Kansas City Power and Light Company calculating the damages from the explosion of its Hawthorn 5 coal-fired generation unit. 2003-2004.

Public Service Commission of Wisconsin, Docket No. 05-CE-130, Direct, Rebuttal and Surrebuttal Testimony on behalf of Wisconsin Electric Power Company regarding energy efficiency and power plant construction. 2003.

Illinois Commerce Commission, Docket No. 01-0423, Phase II, Direct, Rebuttal and Surrebuttal Testimony on behalf of Commonwealth Edison Company concerning the prudence of certain distribution related investments and operating costs , Spring 2003

Illinois Commerce Commission, Docket Nos 02-0656, 71 and 72, (cons) Rebuttal Testimony on behalf of Commonwealth Edison Company concerning the appropriate market value calculation., January 2003

Illinois Commerce Commission, Docket No. 02-0479, Direct and Rebuttal Testimony on behalf of Commonwealth Edison Company concerning the appropriate policy toward provider of last resort service for large (greater than 3MW) usage customers., Summer/Fall 2002

Public Service Commission of Wisconsin, Docket Nos.05-AE-109, 05-CE-117, 05-CE-130, 6650-CG-211, 137-CE-104, Direct Testimony on behalf of Wisconsin Electric Power Company regarding transactions cost economics and vertical integration with implications for power plant construction by local public utilities, June 2002

Public Service Commission of Wisconsin, Docket Nos.05-AE-109, 05-CE-117, 05-CE-130, 6650-CG-211, 137-CE-104, Direct and Rebuttal Testimony on behalf of Wisconsin Electric Power Company regarding energy efficiency and power plant construction, June 2002

New York Public Service Commission, Case No 01-E-0359, Direct Testimony on behalf of New York State Electric and Gas Corporation regarding the appropriateness of the Company's proposed Electric Price Protection Plan., August 3, 2001

Kansas Corporation Commission, Docket No. 01-WSRE-436-RTS, Cross-Answering Testimony on behalf of the City of Topeka, Kansas, regarding cost causation issues and rate parity. April 17, 2001.

North Dakota Public Service Commission, Case No. PU-400-00-195, Direct and Rebuttal testimony on behalf of Otter Tail Power Company regarding application to operate under a performance-based regulation plan., Fall 2000

North Dakota Public Service Commission, Case No. PU-401-00-36, Direct and Rebuttal testimony on behalf of Xcel Energy regarding application to operate under a performance-based regulation plan., Fall 2000

Federal Energy Regulatory Commission, Docket No. EL99-90-000, *City of Wichita, Kansas v Western Resources, Inc* Direct testimony on behalf of the City of Topeka, Kansas focusing on cost causation issues and rate parity., September, 2000

Indiana Utility Regulatory Commission, Cause No. 41753, Direct testimony on behalf of Southern Energy regarding approval of certification of power plant under reduced regulation., August 2000

California Public Utilities Commission, Application A.00-06-032, Direct and rebuttal testimony on behalf of Southern California Gas Company regarding the appropriateness of peaking rate for gas services., Fall 2000

Illinois Commerce Commission, Docket No. 99-0013, Rebuttal testimony on behalf of Commonwealth Edison regarding appropriate treatment of unbundled rates for meter service., June 5, 2000

Indiana Utility Regulatory Commission, Cause No. 41590, Rebuttal testimony on behalf of Southern Energy, n/k/a Mirant regarding approval of certification of power plant under reduced regulation., June 2, 2000

Testimony to Iowa General Assembly concerning electricity deregulation., Spring 2000

Kentucky Public Service Commission, Case No. 2000-095, Testimony on behalf of LG&E Corp. regarding approval of a merger., March 15, 2000

Environmental and Energy Committee of the Illinois State Senate, "Telecommunications Act of 1996: An Assessment and Policy Prescriptions ", February 16, 2000

Illinois Commerce Commission, Docket No. 98-0195, Testimony on behalf of GTE North Inc. and GTE South Inc. regarding investigation into certain payphone issues as directed in Docket 97-0225., December 21, 1999

Public Service Commission of Wisconsin, Docket No. 6630-UR-111, Testimony on behalf of Wisconsin Electric Power Company regarding performance-based regulation., September 1999

South Dakota Public Utilities Commission, Docket No. NG98-010, Testimony on behalf of MidAmerican Energy Company for continuation of its incentive gas supply procurement program., June 1999

Iowa Utilities Board, Docket No. RPU-94-3, Request for Confidential Treatment on behalf of MidAmerican Energy Company. , April 7, 1999

Federal Communications Commission, CC Docket No. 99-24, Affidavit and Reply Affidavit of Karl McDermott and William E Taylor on behalf of Bell Atlantic Telephone Companies for forbearance from regulation as dominant carriers in Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Washington, DC, Vermont and Virginia., January 20, 1999 and April 8, 1999

Illinois General Assembly joint committee on electricity deregulation., Summer 1997

Illinois Public Utilities Committee Telecommunications Subcommittee, Alternative Methods of Telecommunications Regulation , March 27, 1991

Illinois Commerce Commission, Docket No. 80-0167, on the use of incentive mechanisms at Clinton Power Plant construction site.

Illinois Commerce Commission, Docket No. 80-0544, on the use of the variable return to CWIP incentive model in the Illinois Power rate case.

Illinois Commerce Commission, Docket No. 80-0167, rebuttal testimony to Dr. Pappas on the use of incentive mechanisms at the Clinton Power Plant site.

Illinois Commerce Commission, Docket No 80-0367, on the treatment of the time of use pricing standards of the Public Utilities Regulatory Policy Act, (PURPA) for Iowa-Illinois Gas and Electric Company.

Illinois Commerce Commission, Docket No. 81-0478, on the use of q-ratios determining the appropriate rate of return for Illinois Bell Telephone Company.

Illinois Commerce Commission, Docket No. 81-0478, on the appropriate cost of service method for pricing telecommunication service under the transition to competition.

November 2004

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Cost of Common Equity

Low End of Range:	CAPM	11.14 %
High End of Range:	DCF Average	11.98
Recommended Cost of Equity		**11.56 %**

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Value Line Gas LDCs	Exclude the following companies using the specified criteria: Eliminated or Cut Dividends	Operating Revenues from Regulated Entities <80%	Market Cap >$10.0 Billion	Company Involved in Merger	Gas LDC Comparable Group
Cascade Natural Gas **Piedmont Natural Gas** **Northwest Nat. Gas** **Nicor** **Southwest Gas** **KeySpan Corp.** **South Jersey Inds** **Laclede Group** **Peoples Energy** **WGL Holdings Inc** **Energen Corp** **Atmos Energy** **New Jersey Resources** **UGI Corp** **AGL Resources** **NUI Corp.** **SEMCO Energy** **Southern Union**	NUI Corp SEMCO Energy Southern Union	South Jersey Inds Laclede Group Peoples Energy WGL Holdings Inc Energen Corp Atmos Energy New Jersey Resources UGI Corp	None	AGL Resources	**Cascade Natural Gas** **Piedmont Natural Gas** **Northwest Nat. Gas** **Nicor** **Southwest Gas** **KeySpan Corp.**

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota – Gas Utility Operation

A. The Annual Discounted Cash Flow Model

The DCF model implies that the value of an asset is the sum of the future benefits generated by the asset, discounted by the investor's required rate of return. Specifically, the market value of a common stock is equal to the present value of the expected stream of future dividends.

In its general form, the DCF model can be stated as follows:

$$(1)\quad P_o = \frac{D_1}{(1+k_e)} + \frac{D_2}{(1+k_e)^2} + \frac{D_3}{(1+k_e)^3} + \ldots + \frac{D_n}{(1+K_e)^n}$$

where:
- P_0 = the current market price;
- Dt = the expected dividend at the end of period t (where t = 1 to n);
- ke = the cost of common equity; and,
- n = infinity.

If dividends are anticipated to grow at the rate of g each period and $g < k_e$, equation (1) can be rewritten as:

$$(2)\quad P_o = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \frac{D_0(1+g)^3}{(1+k_e)^3} + \ldots + \frac{D_0(1+g)^n}{(1+K_e)^n}$$

where: g = the expected growth rate.

Formula 2 can be reduced to:

$$(3)\quad P_o = \frac{D_1}{k_e - g}$$

Solving Equation (3) for k_e results in the following:

$$(4)\quad k_e = \frac{D_1}{P_o} + g$$

Equation (4) can be restated as:

$$(5) \qquad k_e = \frac{D_o (1+g)}{P_o} + g$$

where: D_o = the most recent dividend.

B. The Quarterly Discounted Cash Flow Model

As shown earlier, if we assume that dividends are anticipated to grow at the rate of g each period and $g < k_e$, then we can rewrite the general DCF equation as:

$$(6) \qquad P_o = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \frac{D_0(1+g)^3}{(1+k_e)^3} + \ldots + \frac{D_0(1+g)^n}{(1+K_e)^n}$$

where:

P_0	=	the current market price;
D_0	=	the current dividend;
k_e	=	the cost of common equity;
g	=	the expected growth rate; and,
n	=	infinity.

If we assume that $(D_{t-1,Q1})$, $(D_{t-1,Q2})$, $(D_{t-1,Q3})$, and $(D_{t-1,Q4})$ represent the quarterly dividend payments at the end of the quarters in the year preceding the date of analysis (t_0) and that dividends are expected to grow as at annual rate of g, then formula 1 can be rewritten as:

$$(7) \qquad P_0 = \frac{(D_{t-1,Q1})(1+g)}{(1+k)^{25}} + \frac{(D_{t-1,Q2})(1+g)}{(1+k)^{50}} + \frac{(D_{t-1,Q3})(1+g)}{(1+k)^{75}}$$

$$+ \frac{(D_{t-1,Q4})(1+g)}{(1+k)} + \sum_{t=1}^{\infty} \sum_{Q=1}^{4} \frac{(D_{t,Q})(1+g)}{(1+k)^{t+25Q}}$$

Equation (7) can be simplified to:

$$(8) \qquad k = \frac{(D_{t,Q1})(1+k)^{75} + (D_{t,Q2})(1+k)^{50} + (D_{t,Q3})(1+k)^{25} + (D_{t,Q4})}{P_0} + g.$$

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In equation 3, k must be solved for through an iterative process. Upon solving k, equation 3 provides the return investors require for investing in a stock that pays dividends quarterly.

C. Use of a Quarterly DCF Model

The discounted cash flow ("DCF") model is a present value model that discounts a stream of expected cash flows to determine their cumulative current value. The timing of the expected cash flows is crucial for an accurate assessment of that value. A key assumption of any present value model, including a DCF model, is that each cash flow is reinvested at the discount rate as soon as it is received. If this assumption is violated, the results of any present value analysis will be biased.

An example will demonstrate how the reinvestment assumption is implicit in present value analysis (including a DCF analysis). Assume an investor has the opportunity to receive one dollar at the end of each quarter of a year for one year. Also assume the investor requires a return of 4% per quarter. The price the investor should be willing to pay for those four quarterly cash flows can be determined using the following formula:

$$PV = \sum_{n=1}^{4} CF_n/(1+k_{eq})^n$$

where:

PV = the price the investor is willing to pay for the investment;

CF_n = the cash flow received at the end of each quarter n; and

k_{eq} = the investor's quarterly required rate of return.

In the above example, the price the investor is willing to pay for the investment opportunity (i.e., the present value of the cash flows) is equal to the following:

$$PV = \frac{\$1}{1.04} + \frac{\$1}{(1.04)^2} + \frac{\$1}{(1.04)^3} + \frac{\$1}{(1.04)^4}$$

$$= \$3.63.$$

Now assume that rather than investing in the four quarterly cash payments, the investor places $3.63 in an investment of equivalent risk that pays 4% interest on a quarterly basis. At the end of the year, the value of the investment can be determined using the following formula:

$$FV = PV(1+k_{eq})^n$$

where:

FV = the value of the investment at the end of the nth period.

In the above example, the value of the investment (i.e., the future value) at the end of the fourth quarter is equal to the following:

$$FV = \$3.63\ (1.04)^4$$
$$= \$4.25.$$

Note that this future value is achieved by compounding (i.e., reinvesting) interest.

The two investments above differ only in the timing of the cash flows. In the former, the investor receives one dollar per quarter for four quarters. In the latter, the investor receives a single payment of $4.25 at the end of the fourth quarter. Given that the prices (i.e., present values), risk and discount rates are identical for the two investments, an investor should be indifferent between the two. Although the investor receives only $4 in the former example (versus $4.25 in the latter example), no inconsistencies exist in the valuation process. The former investment provides the investor with the opportunity to reinvest each cash flow immediately upon receipt, at the discount rate.

The future value of the reinvested cash flow stream is determined using the following formula:

$$FV = \sum_{n=1}^{4} CF_n\ (1+k_{eq})^{4-n}$$

Thus, the future value of the four quarterly, one dollar cash flows, reinvested at the 4% discount rate, is equal to the following:

$$FV = \$1[(1.04)_3 + (1.04)_2 + (1.04)_1 + (1.04)_0]$$
$$= \$4.25.$$

A DCF analysis determines the present value of a stream of future cash flows, assuming the cash flows are reinvested at the discount rate immediately upon receipt. This example illustrates that the reinvestment assumption is implicit in present value analysis.

The DCF analysis was originally developed as a valuation tool. That is, in its most general formulation (See equation 1), the model is used to determine how much an investor should be willing to pay for an investment. In an efficient market, the observed price of a given stock is equal to the discounted value of an expected dividend stream. The discount rate is the investor-required rate of return.

When performing a cost of common equity analysis, analysts observe a Company's current stock price, dividend payment and the timing of dividend payments. By using the observed stock price and correctly modeling the timing of dividend payments, analysts can rearrange a DCF model to estimate the investor-required rate of return on common equity. This cost of equity is implicit in the observed stock price.

As previously stated, the timing of dividend payments is crucial. A simple example should help to clarify this point. Company A and Company B are perceived by investors to have equivalent risk. In an efficient market, if investors perceive the risk of two companies to be equivalent, they will require the same rate of return for investing in either Company. In this example, investors will require a 10% return to invest in either Company. Both Company A and Company B pay $10.00 in dividends over a one-year period. Company A pays a $10.00 dividend at the end of the year, while Company B pays four quarterly dividends of $2.50. Although both companies pay the same total dividend, the dividend of Company B is worth more because investors have the opportunity to reinvest the quarterly dividend payments for the remainder of the year at their required rate of return. By year-end, Company A's dividend is worth $10.00 to investors because Company A pays one $10.00 dividend at the end of the year. Therefore, investors do not have the opportunity to reinvest the quarterly dividend payments throughout the year. The year-end value to investors of Company B's dividend is determined as follows:

* By reinvesting it, the first quarterly dividend will earn a return over the remaining three quarters of the year. By year-end, the first quarterly dividend will be worth $2.69 to investors, computed as follows:

  $[\$2.50(1.1)_{.75}]$.

* By reinvesting it, the second quarterly dividend will earn a return over the remaining two quarters of the year. By year-end, the second quarterly dividend will be worth $2.62 to investors, computed as follows:

  $[\$2.5(1.1)_{.5}]$.

* By reinvesting it, the third quarterly dividend will earn a return over the remaining one quarter of the year. By year-end, the third quarterly dividend will be worth $2.56 to investors, computed as follows:

  $[\$2.50(1.1)_{.25}]$.

* The fourth quarterly dividend will be paid at year-end and will not earn any return by year-end. Hence, the fourth quarter dividend's year-end value to investors will remain $2.50.

* The total year-end value to investors of these four quarterly dividend payments is the summation of each dividend's end-of-year value or $10.37.

Although investors perceive the risks of Companies A and B to be equivalent, and both companies pay $10.00 in dividends over a one year period, investors will pay a higher price for Company B's stock relative to Company A's stock. Investors are willing to pay a higher price for Company B's stock because its dividends are paid quarterly. Company B's four quarterly dividends have a greater year-end value to investors than Company A's single year-end dividend payment. Using the DCF model (equation 3) and, for the sake of simplicity, assuming the investor-expected growth (g) for both companies is 0%, the prices investors should be willing to pay for these companies' stocks are computed as follows:

$$Po = D1/(k-g)$$
$$Pa = \$10.00/(0.1 - 0.0) = \$100.00$$
$$Pb = \$10.37/(0.1 - 0.0) = \$103.70$$

Where:

Pa = the price of Company A's stock;
Pb = the price of Company B's stock;
D1 = the year-end value of the dividend;
k = the investor-required rate of return; and
g = the investor-expected dividend growth rate.

This example demonstrates that investors value stocks based in part upon the timing of dividend payments. In a cost of common equity analysis, the analyst is not attempting to estimate the price of a stock. Rather, an analyst observes the stock price, dividend payment and the timing of dividend payments in any number of financial publications (e.g., The Wall Street Journal) and uses that information to estimate an investor-required rate of return.

In summary, if a Company pays dividends quarterly, its observed stock price (as listed in publications such as The Wall Street Journal) is determined by investors with the understanding that dividends are received and reinvested on a quarterly basis. The quarterly DCF model correctly recognizes the timing of dividend payments and hence their value to investors. Thus the quarterly DCF model will correctly estimate the investor-required rate of return that is implicit in the Company's observed stock price. An annual DCF model will not properly recognize the timing of dividend payments and hence, will understate the investor-required rate of return on equity.

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
30-Day Average Stock Prices

	Company	Ticker Symbol	Stock Price Date [1]	Last Dividend	30-day average Stock Price [1]	30-Day Average Stock Price [4] S&I Adjusted
1	Cascade Natural Gas	CGC	10-Nov-04	0 240	20 87	19 77
2	KeySpan Corp	KSE	10-Nov-04	0 445	39 48	37 38
3	Nicor	GAS	10-Nov-04	0 465	37 50	35 51
4	Northwest Nat Gas	NWN	10-Nov-04	0 325	31 57	29 90
5	Piedmont Natural Gas [2]	PNY	10-Nov-04	0 215	22 58	21 38
6	Southwest Gas	SWX	10-Nov-04	0 205	24 07	22 79

Notes
[1] Yahoo! Finance Research, *http //finance yahoo com,* Closing prices for the 30 days ending on November 10, 2004
[2] Piedmont Natural Gas' stock price reflects a 2 1 stock split that occurred on October 11, 2004 From *The Value Line Investment Survey* , Issue 3, September 17, 2004

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
Dividends

	Company	Recent Quarterly Dividends Paid Per Share (D_0)				Growth [1]	Expected Quarterly Dividend Growth Rate Per Share (D_1)			
		Q_1 ($/Share)	Q_2 ($/Share)	Q_3 ($/Share)	Q_4 ($/Share)	Rate, g (Percent)	Q_1 ($/Share)	Q_2 ($/Share)	Q_3 ($/Share)	Q_4 ($/Share)
1	Cascade Natural Gas	0 240	0 240	0 240	0 240	9 23	0.26	0.26	0.26	0 26
2	KeySpan Corp	0 445	0 445	0.445	0 445	6.77	0.49	0 49	0 49	0 49
3	Nicor	0 465	0 465	0 465	0 465	3.69	0.51	0.51	0 51	0 51
4	Northwest Nat Gas	0 325	0 325	0 325	0.325	5.36	0.36	0 36	0 36	0 36
5	Piedmont Natural Gas	0 208	0 215	0 215	0.215	6 07	0 23	0 23	0 23	0 23
6	Southwest Gas	0.205	0 205	0.205	0.205	10 20	0 22	0 22	0 22	0 22

Notes
[1] Simple average of estimated Value Line EPS growth and B*R+S*V growth
[2] Forward Dividend per Share $D_1 = D_0 (1 + g)$

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
Dividend Yield

	Company	Expected Quarterly Dividend Growth Rate Per Share (D_1)				S&I Adjusted ROE[1]	Expected Quarterly Dividend Growth Rate Per Share (Q_x) Multipied by S&I Adjusted ROE Growth Rate $(1+R/100)^t$				30-Day Average[2] Stock Price	Dividend Yield
		Q_1	Q_2	Q_3	Q_4	R	Y_1	Y_2	Y_3	Y_4	P_0	$\frac{(Y_1+Y_2+Y_3+Y_4)}{P_0}$
		($/Share)	($/Share)	($/Share)	($/Share)	(Percent)					($)	(Percent)
1	Cascade Natural Gas	0 26	0 26	0 26	0 26	14 83	0 29	0 28	0 27	0 26	20 87	5 29
2	KeySpan Corp	0 49	0 49	0 49	0 49	12 21	0 53	0 51	0 50	0 49	39 48	5 15
3	Nicor	0 51	0 51	0 51	0 51	9 61	0 54	0 53	0 52	0 51	37 50	5 61
4	Northwest Nat Gas	0 36	0 36	0 36	0 36	10 29	0 38	0 37	0 36	0 36	31 57	4 67
5	Piedmont Natural Gas	0 23	0 23	0 23	0 23	10 59	0 25	0 25	0 24	0 23	22 58	4 29
6	Southwest Gas	0 22	0 22	0 22	0 22	14 33	0 25	0 24	0 23	0 22	24 07	3 92

Notes

[1] ROE adjusted by selling and issuance expenses

[2] Yahoo! Finance Research, http://finance.yahoo.com, Closing prices for the 30 days ending on November 10, 2004

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
DCF Cost of Equity

	Company	Dividend [1] Yield (Percent)	Growth [2] Rate, g (Percent)	Unadjusted [3, 4] ROE, k_e Before S&I (Percent)		Change (Percent)		S&I [5] Adjusted ROE (Percent)	
1	Cascade Natural Gas	5.29	9.23	14.53		0 30		14 83	
2	KeySpan Corp.	5.15	6.77	11.92		0.29		12 21	
3	Nicor	5 61	3.69	9.29		0 31		9.61	
4	Northwest Nat. Gas	4.67	5.36	10 03		0.26		10 29	
5	Piedmont Natural Gas [8]	4.29	6.07	10.35		0.24		10 59	
6	Southwest Gas	3.92	10.20	14.11		0.22		14 33	
	Average	**4.82**	**6.89**	**11.71**	**%**	**0.27**	**%**	**11.98**	**%**

Notes

[1] Dividend Yield = [(Total D_0*(1+Growth Rate))/Stock Price]

[2] Simple Average of Value Line EPS and BR+SV growth rates

[3] Not adjusted for selling and issuance expenses

[4] ROE adjusted by selling and issuance expenses

Piedmond Natural Gas' stock price reflects a 2 1 stock split that occurred on October 11, 2004 From The Value Line Investment Survey,

[5] Issue 3, September 17, 2004

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
Growth Rate Estimates

	Company	Value Line EPS [1] 2003 ($)	Value Line EPS [1] 2007-2009 ($)	Estimated VL Growth [2] (Percent)	B*R+S*V Growth (Percent)	Average Growth [3] (Percent)
1	Cascade Natural Gas	0 87	1.65	13 66	4 81	9 23
2	KeySpan Corp.	2.62	3.45	5 66	7 89	6 77
3	Nicor	2 11	2.50	3 45	3 92	3 69
4	Northwest Nat Gas	1 76	2 40	6 40	4 33	5 36
5	Piedmont Natural Gas	1 11	1.55	6 91	5.23	6 07
6	Southwest Gas	1 13	2.15	13.73	6 67	10 20
	Average:			**8.30 %**	**5.47 %**	**6.89 %**

Notes

[1] *The Value Line Investment Survey* , Issue 3, September 17, 2004

[2] ([2007-2009 EPS Estimate]/[2003 EPS]^0 20-1)*100

[3] Simple average of Estimated Value Line EPS growth and B*R+S*V growth

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
Sustainable Growth Method

	Company	R Estimated Return on Common Equity [1] (Percent)	D_e Estimated Dividend Per Share [1] ($)	V_e Estimated Book Value Per Share [1] ($)	V Book Value Per Share 2003 ($)	V Book Value Per Share 2002 ($)	R_{av} Return on Average Equity [2] (Percent)	B [3] (Percent)	B*R [4] (Percent)	S*V Average (Percent)	B*R+S*V [5] (Percent)
1	Cascade Natural	12 00	0 98	13 75	10 11	10 34	11 87	39 93	4 74	0 07	4 81
2	KeySpan Corp	12 00	1 90	29 25	22 94	20 67	12 62	48 55	6 13	1 76	7 89
3	Nicor	16 50	2 00	16 60	17 13	16 55	16 78	28 22	4 74	(0 81)	3 92
4	Northwest Nat Gas	10 00	1 45	23 50	19 52	18 88	10 17	39 31	4 00	0 33	4 33
5	Piedmont Natural	10 50	0 95	14 40	9 36	8 91	10.76	38 68	4 16	1 07	5 23
6	Southwest Gas	9 50	0 82	23 25	18 42	17 91	9 63	63 39	6 11	0 56	6 67
	Average:										**5.47 %**

Source *The Value Line Investment Survey*, Issue 3, September 17, 2004

Notes

[1] 2007-2009 estimated return on common equity, dividends per share, and book value per share as reported in Value Line

[2] $Rav=(2*R*V_{01})/(V_{01}+V_{00})$

[3] B=1-(De/(Rav*Ve))

[4] B*R=B*Rav=(Rav-De/Ve)

[5] S*V equals five year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
S and V Estimation

	Company	Growth Rate of Common Shares Outstanding (S) 1999 (a)	2000 (b)	2001 (c)	2002 (d)	2003 (e)	Average S [1] (f)	V [2] (g)	S*V (h)=|(f)*(g)|
1	Cascade Natural Gas	0 0000	0 0000	0 0000	0 0000	0 0072	0 0014	0 5157	0 0007
2	KeySpan Corp	0 0265	0 0186	0 0225	0 0214	0 1211	0 0420	0 4189	0 0176
3	Nicor	(0 0130)	(0 0299)	(0 0240)	(0 0088)	0 0007	(0 0150)	0 5432	(0 0081)
4	Northwest Nat Gas	0 0097	0 0056	0 0000	0 0143	0 0137	0 0086	0 3817	0 0033
5	Piedmont Natural Gas	0 0181	0 0198	0 0172	0 0193	0 0171	0 0183	0 5855	0 0107
6	Southwest Gas	0 0191	0 0232	0 0246	0 0246	0 0282	0 0240	0 2348	0 0056

Source *The Value Line Investment Survey*, Issue 3, September 17, 2004

Notes
[1] Average common shares outstanding growth rate for 1999-2003
[2] V = (1-(2002 Book Value per Share/Average Stock Price))

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Equity Issuance Expense

SEC Filing Date	Number of Shares Issued (No.)	Market Price Price/Share ($)	Offering Price Price/Share ($)	Proceeds ($)	Per Share Underwriting Discounts & Commissions ($)	Total Underwriting Discounts & Commissions ($)	Net Proceeds [1] ($)	Estimated Company Expenses ($)	Selling & Issuance Costs [2] (Percent)	
11/16/1949	1,584,238	10 75	10 25	17,030,559	0 26	413,486	15,824,953	792,119	7 08	
6/4/1952	1,108,966	10 50	10 50	11,644,143	0 26	288,331	11,355,812	-	2 48	
4/14/1954	1,219,856	15 20	14 00	18,541,811	0 18	224,454	16,853,530	1,524,820	9 40	
2/29/1956	670,920	17 83	16 75	11,959,149	0 27	181,819	11,056,091	721,239	7 55	
7/22/1956	952,033	23 38	22 00	22,253,771	0 26	247,529	20,697,197	1,309,046	6 99	
7/28/1965	772,008	35 25	33 00	27,213,282	0 32	244,727	25,231,537	1,737,018	7 28	
1/22/1969	1,080,811	29 00	27 00	31,343,519	0 31	330,728	28,851,169	2,161,622	7 95	
10/21/1970	1,729,298	23 13	21 50	39,990,016	0 32	560,293	36,619,614	2,810,110	8 43	
7/26/1972	1,902,228	25 00	23 50	47,555,700	0 30	561,157	44,141,201	2,853,342	7 18	
10/10/1973	2,092,451	25 83	24 50	54,037,547	0 28	587,979	50,677,071	2,772,497	6 22	
11/20/1974	2,300,000	17 63	17 50	40,537,500	0 98	2,251,700	37,998,300	287,500	6 26	
8/14/1975	1,750,000	23 00	23 00	40,250,000	0 82	1,429,750	38,820,250	-	3 55	
6/3/1976	2,000,000	24 00	24 00	48,000,000	0 78	1,568,000	46,432,000	-	3 27	
5/31/1993	3,041,955	44 13	43 63	134,226,264	1 25	3,796,360	128,908,927	1,520,978	3 96	
9/23/1997	4,500,000	49 94	49 56	224,721,000	1 36	6,133,500	216,900,000	1,687,500	3 48	
9/29/1997	400,000	50 50	49 56	20,200,000	1 36	545,200	19,280,000	374,800	4 55	%
2/25/2002	20,000,000	22 95	22 50	459,000,000	0 75	14,900,000	435,100,000	9,000,000	5 21	
Weighted Average [4]									**5.11**	%
Borun and Malley [3]									**5.50**	
Average Expense									**5.31**	
Issuance Expense Adjustment									**94.69**	%

Notes
[1] Net Proceeds = Proceeds - Total Underwriting Discounts & Commissions
[2] Selling & Issuance Costs = (Total Underwriting Discounts & Commissions + Estimated Company's Expenses)/Proceeds
[3] Victor M Borun and Susan L Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly* , February 20, 1986, pp 33-39
[4] Derived from company-provided issuance data

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Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
Comparable Group
Capital Asset Pricing Model (CAPM)

No	Company	30-Year T-Bond Return (Rf)[1]	Beta Value Line[2]	Market Risk Premium Top-Down DCF - 30 Yr T-Bond Return[3,4]	CAPM Cost of Equity[5] Top-Down DCF - 30 Yr T-Bond Return
		%			%
1	Cascade Natural Gas	4 82	0 75	8 07	10 87
2	KeySpan Corp	4 82	0 75	8 07	10 87
3	Nicor	4 82	1 00	8 07	12 89
4	Northwest Nat Gas	4 82	0 65	8 07	10 07
5	Piedmont Natural Gas	4 82	0 75	8 07	10 87
6	Southwest Gas	4 82	0 80	8 07	11 28
	Average		**0.78**		**11.14**

Notes

[1] From *The Value Line Selection and Opinion*, November 5, 2004

[2] From *The Value Line Investment Survey*, Issue 3, September 17, 2004

[3] The formula used is Risk Premium [RM - RF] = [12 89% - 4 82%]

[4] Dividend yield for S&P 500 is from Standard & Poors Online, Indices, S&P 500, Month End Data Five-year earnings growth rate is from Yahoo! Finance (First Call) for September 20, 2004 More recent analyst estimate for the S&P 500 growth rate is not readily available

[5] Cost of Equity = RF + Beta (RM - RF), where RF is the return on the 30-year Treasury Bond, and (RM - Rf) is the market premium computed as described in footnote [3] and [4]

Prepared by:
Karl A McDermott Ph D, Vice President
National Economic Research Associates, Inc

Northern States Power Company d/b/a Xcel Energy
State of North Dakota - Gas Utility Operation
DCF of the S&P 500

Dividend Yield S&P 500 [1]	1.78	%
Growth Rate S&P 500 [2]	10.81	%
DCF S&P 500 [3]	12.78	%
Issuance Expense	0.11	%
Total DCF S&P 500	12.89	%

Notes.

[1] From Standard & Poors S&P 500 Earnings and Estimate Report.

[2] Yahoo! Finance (First Call) for September 20, 2004 More recent analyst estimate for the S&P 5

[3] DCF=(Div Yield*(1+Growth))+Growth

[4] Total DCF = (DCF S&P 500)(1-Average Issuance Expense) + Growth Rate S&P 500

Prepared by:
Karl A. McDermott Ph.D, Vice President
National Economic Research Associates, Inc.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **2nd day of December, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of

Order

The envelopes were addressed as follows

Dave Sederquist
Northern States Power Company
400 N 4th St
Bismarck ND 58501
Cert. No. 7003 2260 0001 3517 9107

Kent T Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3517 9114

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis MN 55401
Cert. No. 7003 2260 0001 3517 9121

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Sandra L Scott
Notary Public

Subscribed and sworn to before me
this **2nd day of December, 2004**

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

14 PU-04-578 Pages 5
Affidavits of Service
by Public Service Commission
12/02/2004 CC Comm Legal PUD (4) Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **2nd day of December, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Order

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Subscribed and sworn to before me
this **2nd day of December, 2004**.

Sandra L. Scott

Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

dhawk@simplot.com
David Hawk
J R Simplot
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Boise ID 83707-0027

rickstensby@clearchannel.com

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patmclean@clearchannel.com

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Laurie Baranko
Dakota Resource Council
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Dickinson ND 58602-1095

Jerry Tuchscherer
Grand Forks Board of Realtors
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Grand Forks ND 58201-6761

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Jay Casler
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White Plains NY 10601-4425

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Harvey ND 58341-0006

KHRT AM
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Minot ND 58702-1210

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King Publishing Co
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Knoxville TN 37950-2210

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Bismarck ND 58501

Myer Shark
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3630 Phillips Pkwy
St Louis Park MN 55426

KNOX-AM & KRRK-FM
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Grand Forks ND 58208-3638

KTHI-TV
PO Box 12427
Grand Forks ND 58208-2427

Minnesota PUC
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St Paul MN 55101-2147

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Bismarck ND 58501

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NARUC
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Washington DC 20005

Robert Burns
National Regulatory Research Inst
406 Bevis Hall 1080 Carmack
Columbus OH 43210

Scott Speaker
Natural Gas Week
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Washington DC 20005-2150

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NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

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The Vogel Law Firm
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Bismarck ND 58502-2097

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Xcel Energy
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St Paul MN 55117

Dennis Lavallee
Nat'l Assoc Plumbing-Htng-Cooling
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Falls Church VA 22046-6808

Harlan Fuglesten
ND Association of RECs
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Mandan ND 58554-0727

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

MOTION

APPROVED
DATE: 12-1-04
KME

December 1, 2004

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission adopt the Order on interim rates in Northern States Power Company's Natural Gas Rate Increase Application, Case No PU-04-578

sdh

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

ORDER

December 1, 2004

On November 4, 2004, Northern States Power Company (NSP) filed an application to increase its natural gas rates The application included an interim rate increase

Under N D C C section 49-05-06(2) a company filing for a rate increase is entitled to an interim increase, but the rate increase must meet certain criteria These include the same rate of return on common equity authorized by the Commission in the public utility's most recent rate proceeding, rate base and expense items the same in nature and kind allowed by the Commission in its most recent rate proceeding and, no change in the existing rate design

NSP's interim rate increase is based on a projected 2004 test year and seeks an increase in annual revenue collections of $741,000, or an overall increase in retail revenues of 1 08% To accomplish this, NSP filed an Interim Rate Adjustment of 5 84% be applied to the non-gas portion of the bill (the customer charge plus the distribution charge) The Interim Rate Adjustment will be shown as a separate line item on customer bills

On November 23, 2004, the commission's advocacy staff filed comments stating that NSP's interim rate request complies with North Dakota Century Code § 49-05-06 (2)

In the event the interim rate amounts collected by NSP are in excess of the final rates approved by the Commission, NSP is required to make refund under North Dakota Century Code § 49-05-06 (4), to persons entitled thereto, including interest at a rate to be determined by the Commission

Order

The Commission orders

1 Northern States Power Company's proposed interim rates shall be effective for service rendered on or after January 1, 2005

2 Northern States Power Company is not required to obtain a bond under North Dakota Century Code § 49-05-06 (3) to secure a refund required under North Dakota Century Code § 49-05-06 (4)

PUBLIC SERVICE COMMISSION

Susan E. Wefald
Commissioner

Tony Clark
President

Kevin Cramer
Commissioner

12 PU-04-578 Pages 1
Order
by Public Service Commission
12/01/2004 CC Comm Legal Fold (4) Mike

NORTH DAKOTA IVN INTERACTIVE VIDEO NETWORK

2004 Meeting Scheduli. Form

Parts highlighted in yellow are required information.

Reservation Number (s)

Date Requested: November 22, 2004

Requested by & Address:
ND Public Service Commission
600 E. Blvd. Ave. Dept. 408
Bismarck, ND 58505-0480

Phone: 701-328-4081

E-mail Address: slscott@state.nd.us

TITLE OF EVENT: Public Input Session, Case No. PU-04-578, Northern States Power Co., Natural Gas Rate Increase, Application

NOTE. List all times in Central Standard Time

Preferred Date February 7, 9 or 10, 2005 (which ever date is available)	Day of the Week Monday, Wednesday Or Thursday	Start Time AM/PM 7 p.m.	End Time AM/PM 9 p.m.
Alternate Date	Day of the Week	Start Time AM/PM	End Time AM/PM

SITES: Identify host site with an H; identify all receiving sites with an X. Note: Limit of 12 Sites

HIGHER ED SITES

Bismarck- Bismarck State College	H	Jamestown State Hospital	
Bottineau – MiSU Bottineau		Mayville – Mayville State Univ.	
Devils Lake – Lake Region State College		Minot – Minot State Univ.	
Dickinson – Dickinson State Univ.		Valley City – Valley City State Univ.	
Fargo - NDSU	X	Wahpeton – ND State College of Science	
Grand Forks - UND	X	Williston – Williston State College	

TRIBAL COLLEGES

Belcourt-Turtle Mt CC		Fort Yates – Sitting Bull College	
Bismarck-United Tribes Tech		McLauglin, SD – Sitting Bull College	
Fort Totten - CCCC		New Town – Ft. Berthold Community College	

If you wish to use sites other than higher ed, first you need to contact the site to check for its availability. List the site below with name of city first followed by site name. A listing of other sites can be found on the IVN website at www.ndivn.nodak.edu under Site Information, Directory of Sites

For other sites list city first then, site name (i.e.building name and room number)

OTHER SITES	ROOM PHONE NUMBER	ROOM FAX NUMBER

NOTE: It is the responsibility of the individual requesting the meeting/class to obtain the ROOM PHONE ROOM FAX numbers of the other sites.

Event Facilitator: Public Service Commission
Phone: 701-328-4081 **E-mail Address:** slscott@state.nd.us

Check Resources Needed – NOTE: not all sites have audio/visual equipment listed below.

VCR : X	DVD:	Document Camera:	Laptop Computer:	Guest Speaker:

Billing:

	C: NDUS Users – Classes & Meetings		F: Non-Profit Groups - $80/hour + 10/hour/site + Admin fee $50 + $25/site
	D: NDUS Grants/Fees/Campus Membership - $80/hour + $10/hour/site		G: Tribal Colleges – per agreement
X	E: State Gov't/Political Subdivisions/K-12 $80/hour + $10/hour/site		H: Multi-state Conference –Admin Fee - $50 Other applicable charges depending upon type of connection and sites involved.

** STREAMED EVENT

WORD/Forms **E-mail form to scheduling@mail.und.nodak.edu**

Pages 1

PU-04-578

2004 ... Meeting Scheduling ...

by Public Service Commission

11/22/2004

CC Comm Legal PUD (4) Mike

11

9 **PU-04-578** Pages

Will not be filing a bid proposal

by Doherty & Company Inc

11/30/2004 CC Comm Legal PUC (4) Mike

10 **PU-04-578** Pages 47

Response to Request for Proposal

by Thornton Financial Consulting

11/30/2004 CC Comm Legal PUC (4) Mike

Memo

RECEIVED
NOV 23 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

To: Commissioners, Bill & PUD

From: Mike Diller

Date: November 23, 2004

Re: NSP's Interim Rate Increase Request (PU-04-578)

According to staff's review of NSP's application for interim rate relief, NSP uses a 2004 projected test year to calculate its interim rate relief. The rate of return on common equity used is 11.5% which coincides with the commission's last order in Case No. PU-400-00-521.

In the last order, the commission disallowed the inclusion of unamortized gas clean-up costs, related to an old manufactured gas plant site, in rate base. The requested interim rates properly exclude this component from rate base.

The company also adjusts its projected rate base to exclude costs related to hedging. Hedging costs were not included in the last rate case and therefore appropriately adjusted out in accordance with the law.

The company properly includes short term debt in its capital structure and the conversion of common equity to long-term debt in accordance with the last commission order.

The company properly applies the interim rate increase of 5.84% across-the-board to the non-gas portion of the tariff rates of all customer classes.

Even though the commission may require a bond to ensure a refund in the event that the commission does not find in NSP's favor, staff believes the financial security of NSP is such that one is not required.

In summary, staff believes that NSP's filing comports with newly enacted legislation and should be approved.

Following are the applicable laws governing the interim gas rate increase requested by NSP:

8 PU-04-578 ages 2

Staff's review of NSP's appliation for interim rate relief
by Public Service Commission by Mike Diller

11/23/2004comm Legal ifona Pat, Jerry Annette Mike

49-05-06. Hearing by commission on proposed change of rates.

2. **Notwithstanding that the commission may suspend a filing and order a hearing, a public utility may file for interim rate relief as part of its general rate increase application and filing. If interim rates are requested, the commission shall order that the interim rate schedule take effect no later than sixty days after the initial filing date and without a public hearing. The interim rate schedule must be calculated using the proposed test year cost of capital, rate base, and expenses, except that the schedule must include:**

   a. **A rate of return on common equity for the public utility equal to that authorized by the commission in the public utility's most recent rate proceeding;**

   b. **Rate base or expense items the same in nature and kind as those allowed by a currently effective commission order in the public utility's most recent rate proceeding; and**

   c. **No change in existing rate design.**

3. **In ordering an interim rate schedule, the commission may require a bond to secure any projected refund required by subsection 4. The terms of the bond, including the amount and surety, are subject to the commission's approval.**

4. **As ordered by the commission, the utility shall promptly refund to persons entitled thereto all interim rate amounts collected by the public utility in excess of the final rates approved by the commission plus reasonable interest at a rate to be determined by the commission.**

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

November 19, 2004

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747

Dear Mr. Sederquist:

On November 18, 2004, the Commission suspended the rates filed with Northern States Power Company's Natural Gas Rate Increase application, Case No. PU-04-578.

If you have any questions concerning this action, let us know.

Sincerely,

Sharon Helbling
Public Utilities Division

sdh

7 PU-04-578 Pages 1

Letter to Excel re suspension of rates

by Public Service Commission

11/19/2004omm Legal Illona Pat Jerry Annette Mike

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY CERTIFIED AND ORDINARY MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **19th day of November, 2004**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and containing a photocopy of:

Request for Proposal

The envelope was addressed as follows

Dave Sederquist
Xcel Energy
P O Box 2747
Fargo ND 58108-2747
Cert. No. 7001 2260 0001 3517 1453

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Sharon Helbling

Subscribed and sworn to before me
this **19th day of November, 2004**.

Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that

she is over the age of 18 years and not a party to this action and, on the **19th day of November, 2004**, she sent by E-Mail or deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Request for Proposal

The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address

Sharon Helbling

Subscribed and sworn to before me
this **19th day of November, 2004**.

Sandra L Scott
Notary Public

SEAL

SANDRA L SCOTT
Notary Public
State of North Dakota
My Commission Expires June 11, 2010

Notary Public

Jim Nessa
503 W Laurel
Fergus Falls MN 56537

John Grinager
1454 Simpson St
St Paul MN 55108

William Lang
2915 Bronson Dr NE
St Paul MN 55112

Barbara Alexander
15 Wedgewood Dr
Winthrop ME 04364

Arturo Abacan
AUS Inc
PO Box 1050
Moorestown NJ 08057-1050

Ben Johnson Associates Inc
2252 Killearn Ctr Blvd Ste 2D
Tallahassee FL 32308-3573

Benjaman Schlesinger & Assoc Inc
The Bethesda Gateway
7201 Wisconsin Ave Ste 740
Bethesda MD 20814

David Effron
Berkshire Consulting Service
386 Main St
Ridgefield CT 06877

Economics Dept
Black Hills State University
1200 University St
Rapid City SD 57783

Jennifer Whitley
Business Discount Plan Inc
1 World Trade Ctr Ste 800
Long Beach CA 90831-0800

Ila Feld
Communications Dispute Resolutions
1 SE 3rd Ave Ste 1450
Miami FL 33131

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Moorhead MN 56562

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Accounting Dept
Concordia College
Moorhead MN 56562

Business Dept
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Business Dept
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Fargo ND 58105

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Aberdeen SD 57401

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Fergus Falls MN 56538-0496

Finance Dept
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215 S Cascade Street
Fergus Falls MN 56538-0496

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Burlington MA 01803-5154

Bob Pressey
Ryan Murphy Inc
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Northglenn CO 80233-1100

Schumaker & Company
117 N 1st St Ste 60
Ann Arbor MI 48104

Charles W King
Snavely King Majoros O'Connor & Lee I
1220 L St NW Ste 410
Washington DC 20005

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Rapid City SD 57701

Accounting Dept
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500 E Saint Joseph
Rapid City SD 57701

Economics Dept
South Dakota School of Mines
500 E Saint Joseph
Rapid City SD 57701

Business Dept
South Dakota School of Mines
500 E Saint Joseph
Rapid City SD 57701

Finance Dept
South Dakota School of Mines
500 E Saint Joseph
Rapid City SD 57701

Engineering Dept
South Dakota State University
Brookings SD 57007

Accounting Dept
South Dakota State University
Brookings SD 57007

Economics Dept
South Dakota State University
Brookings SD 57007

Business Dept
South Dakota State University
Brookings SD 57007

Finance Dept
South Dakota State University
Brookings SD 57007

Stone & Webster Managements Consultants
250 W 34th St
New York NY 10119

Strategic Energy Services Inc
105 Leblank Ct
Cary NC 27513-3542

Tel Tech Inc
1300 W 57th St Ste G204
Sioux Falls SD 57108-2885

Tellus Institute
11 Arlington St
Boston MA 02116

Ajay Sanghi
The Analyst
P O Box 552
Delmar NY 12054-0552

Engineering Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Accounting Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Economics Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Telecomm Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Business Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Finance Dept
University of North Dakota
Box 8193
Grand Forks ND 58202-7141

Finance Dept
University of South Dakota
414 E Clark
Vermillion SD 57069

Accounting Dept
University of South Dakota
414 E Clark
Vermillion SD 57069

Economics Dept
University of South Dakota
414 E Clark
Vermillion SD 57069

Business Dept
University of South Dakota
414 E Clark
Vermillion SD 57069

Gene Griffin
Upper Great Plains Transp Institute
PO Box 5074
Fargo ND 58105-5074

Washington Utility Group
2120 L St NW Ste 520
Washington DC 20037-1527

Watson Consulting
16376 SE Van Zyl Rd
Clackamas OR 97015

Robert Feder
Wold Johnson P C
PO Box 1680
Fargo ND 58107-1680

Wolfe & Associates
1110 College Dr Ste 206
Bismarck ND 58501-1207

Bryce Freeman
Wyoming PSC
700 W 21st St
Cheyenne WY 82002

APPROVED
DATE: 11-18-04
KMF

MOTION

November 18, 2004

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission issue a Request for Proposal for consulting services in Northern States Power Company's Natural Gas Rate Increase application, Case No. PU-04-578

MRD

5 **PU-04-578** Pages 1

Motion to issue a Request for Proposal

by Public Service Commission

11/18/2004mm Legal Ilona Pat Jerry Annette Mike

Public Service Commission
State of North Dakota

COMMISSIONERS

Tony Clark, President
Susan E Wefald
Kevin Cramer

Executive Secretary
Illona A Jeffcoat-Sacco

600 E Boulevard Ave Dept 408
Bismarck, North Dakota 58505-0480
web www psc state nd us
e-mail ndpsc@state nd us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

REQUEST FOR PROPOSAL

To: Potential Bidders

From. Illona A. Jeffcoat-Sacco, Executive Secretary

Date: November 18, 2004

Re. Request for Proposal, Case No. PU-04-578

The North Dakota Public Service Commission is requesting written proposals from selected firms to assist commission staff in its investigation of Northern States Power Company's (NSP's) gas rate increase request NSP seeks a 1.8% increase in overall natural gas revenues.

According to its filing, NSP's rate increase request stems from investment related costs associated with meeting growth and revenue erosion caused by declining use per customer.

Even though the overall revenue increase request is only 1.8%, the requested revenue increase for residential customers is 4 6%--even greater for low use customers. The average residential revenue increase excluding the cost of gas is 20 7% (55% increase in the customer charge from $5 50 to $8 50; and a slight decrease in the distribution charge) According to NSP's class cost of service study, residential revenues should be increased by 11% to ensure that the residential class pays for its fair share of costs while revenues of other classes should be reduced

The commission seeks assistance in evaluating the overall reasonableness of NSP's rate increase request The completion date for the investigation and written testimony is March 1, 2005. The technical hearing will be scheduled for mid to late April, 2005.

The specific purpose is to investigate, analyze and provide testimony regarding the fairness and reasonableness of NSP's proposed rate base, cost of capital, regulated net income and rate design Consulting duties include:

1 Professional analysis and review of the filing
2 Prepare and conduct discovery as necessary
3. Monthly progress reports of discovery, conclusions and recommendations
4 Prepare and file written testimony

4 PU-04-578 Pages 3
Request for Proposal
by Public Service Commission
11/18/2004mm Legal Illona Pat Jerry Annette Mike

5 Provide oral testimony
6 Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding
7 Assist staff in the preparation of proposed findings of fact.

The staff may select firms to be interviewed Selection will be based on an evaluation using the following criteria

1 Quality of written proposal (5 points).
2 Capability, including personnel qualifications, experience, training, education, and performance record (20 points)
3 Understanding of the project (20 points)
4. Proposed work approach (10 points).
5. Price (45 points)·
   a. Lowest to 120% of lowest bid = 45 points
   b. 121% to 130% of lowest bid = 44 points
   c. 131% to 140% of lowest bid = 42 points
   d. 141% to 150% of lowest bid = 38 points
   e. 151% to 160% of lowest bid = 32 points
   f 161% to 170% of lowest bid = 24 points
   g 171% to 180% of lowest bid = 14 points
   h. 181% to 190% of lowest bid = 2 points
   i. 191% and over of lowest bid = 0 points

The written proposal should include a fixed price.

Resumes of those professionals directly providing services should be included along with examples of any past work similar to that required in this project. In addition, those who have not previously contracted should provide at least three client references.

Staff will make recommendations to the commission. The commission may consider hiring a consultant to perform any one of the identified tasks or portions of the identified tasks. The commission has the right to enter into competitive negotiations with qualified bidders for the purpose of selecting a consultant to perform all or a portion of the identified work. The commission retains the right to reject any and all proposals.

The successful contractor will be required to comply with all applicable Equal Employment Opportunity laws and regulations All proposals shall include certification that they comply with applicable provisions of the Americans with Disabilities Act of 1991. A signed "Conflict of Interest Disclaimer" must accompany all proposals and will be made part of the final contract.

Written proposals from qualified consultants will be accepted until the close of business December 6, 2004.

Submit an original and five copies of proposals to.

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Sincerely,

Illona A Jeffcoat-Sacco
Executive Secretary

APPROVED
DATE 11-18-04
KME

MOTION

November 18, 2004

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission suspend Northern States Power Company's rates filed with its Natural Gas Rate Increase application in Case No PU-04-578

sdh

APPROVED
DATE: 11-18-04
KMF

MOTION

November 18, 2004

Northern States Power Company
Natural Gas Rate Increase
Application

Case No. PU-04-578

I move the Commission appoint Bill Binek, Mike Diller and Jerry Lein as advocacy staff, and Illona Jeffcoat-Sacco, Patrick Fahn and Annette Bendish as advisory staff in Northern States Power Company's Natural Gas Rate Increase application in Case No PU-04-578.

sdh

2 PU-04-578 Pages 1

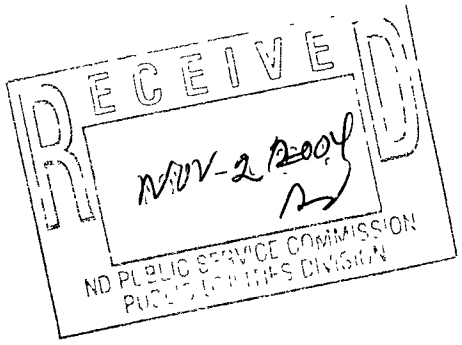
Motion regarding staff appointments

by Public Service Commission

11/18/2004 mm Legal Illona Pat Jerry Annette Mike

Xcel Energy℠

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747



Gas Utility
State of North Dakota

Notice of Change in Rates
For Natural Gas Service

Submitted
November 2, 2004

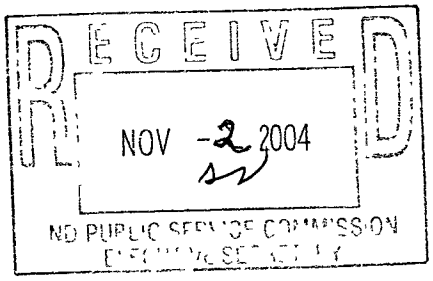
1 PU-04-578 Pages 158
Notice of Change in Rates for Natural Gas Service
by Northern States Power Company by
11/02/2004omm Legal Illona, Pat Jerry Annette Mike

Xcel Energy℠

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
(701) 241-8632
dave sederquist@xcelenergy com

November 2, 2004

Illona A Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 58505-0480



Re Northern States Power Company d/b/a Xcel Energy
Notice of Change in Rates for Natural Gas Service

Dear Ms. Jeffcoat-Sacco:

Pursuant to North Dakota Century Code ("N D Cent. Code") § 49-05-05, Northern States Power Company d/b/a Xcel Energy ("the Company" or "Xcel Energy") submits an original and seven (7) copies of a Notice of Change in Rates for Natural Gas Service ("Notice") The Notice proposes an increase in the natural gas rates stated in the Company's North Dakota Gas Rate Book of $1.3 million or 1.8% annually The Notice also proposes changes to certain tariff terms and conditions of service. The rate changes would be effective December 2, 2004, unless suspended by the Commission.

Also enclosed as part of this Notice is an Alternative Petition for Interim Rates, should the Commission suspend the general Notice of Change in Rates Pursuant to N.D Cent. Code 49-05-06, Subd. 2, interim rates would be effective January 1, 2005, 60 days after filing.

This filing includes the Notice, revised tariff rate schedules reflecting the change in rates (both regular and legislative versions), a comparison of the proposed rates to present rates, a typical bill impact analysis, and an affidavit In addition, Xcel Energy is providing other schedules supporting the need for the gas tariff rate change in more detail If necessary, testimony will be filed in accordance with any procedural schedule established by the Commission. Pursuant to N.D Cent Code § 49-05-05, Xcel Energy has prepaid the filing fee of $50.00 through its periodic regulatory fee payments to the Commission.

Please affix the Commission's filing stamp to the extra copy of the Notice and return it to Mr. Sederquist in the enclosed pre-paid envelope. You may direct any questions regarding this Notice or the Alternative Petition for Interim Rates to Mr Dave Sederquist at (701) 241-8632 or Mr Jim Johnson at (612) 215-4592

Sincerely,

David H Sederquist
Sr Consultant, Regulation & Finance
Northern States Power Co d/b/a Xcel Energy

Enclosures

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Notice of Change	)	
In Rates for Natural Gas Service	)	
By Northern States Power Company	)	
d/b/a Xcel Energy	)	Case No. PU-400-04-578

AFFIDAVIT OF
Kent T. Larson

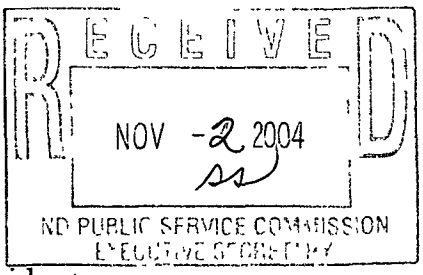
I, the undersigned, being first duly sworn, on oath depose and say that I am Vice-President for Northern States Power Company d/b/a Xcel Energy ("Company"), the applicant herein; that I have read the foregoing Notice of Change in Rates For Natural Gas Service and the Alternative Petition For Interim Rates and that I believe all statements therein to be true and correct; and that said filings are submitted and signed on behalf of said Company with the consent and authority of the Company.

Kent T. Larson

Subscribed and sworn to ~~before~~ me, this 2 day of November, 2004.

Natalie Maczka
Notary Public

NATALIE MACZKA
NOTARY PUBLIC • MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2009



STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Tony Clark — President
Susan E. Wefald — Commissioner
Kevin Cramer — Commissioner

IN THE MATTER OF THE NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

CASE NO. PU-400-04-578

NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE

I. INTRODUCTION

Pursuant to N.D. Cent. Code § 49-05-05 and N.D. Admin. Code 69-09-01-26, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") hereby provides notice to the North Dakota Public Service Commission ("NDPSC" or "Commission") of the Company's intent to change natural gas rates and tariffs contained in the Company's North Dakota Gas Rate Book effective December 2, 2004, thirty (30) days after the date of this Notice. However, if the Commission suspends the proposed revised rates and tariffs within 30 days of this notice of rate change, the Company respectfully requests the Commission issue an order granting interim rate relief effective January 1, 2005, sixty (60) days after filing, without a hearing, pursuant to N.D. Cent. Code. § 49-05-06, Subd. 2. A separate Alternate Petition for Interim Rates is submitted with this notice.

The rate and tariff changes would result in an annual increase of natural gas revenues of $1,280,232, or 1.8%, effective for natural gas usage on and after December 2, 2004, or upon final approval if the rates are suspended and interim

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Tony Clark	President
Susan E. Wefald	Commissioner
Kevin Cramer	Commissioner

IN THE MATTER OF THE NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY	CASE NO. PU-400-04-____
	NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE

I. INTRODUCTION

Pursuant to N.D. Cent. Code § 49-05-05 and N.D. Admin. Code 69-09-01-26, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") hereby provides notice to the North Dakota Public Service Commission ("NDPSC" or "Commission") of the Company's intent to change natural gas rates and tariffs contained in the Company's North Dakota Gas Rate Book effective December 2, 2004, thirty (30) days after the date of this Notice. However, if the Commission suspends the proposed revised rates and tariffs within 30 days of this notice of rate change, the Company respectfully requests the Commission issue an order granting interim rate relief effective January 1, 2005, sixty (60) days after filing, without a hearing, pursuant to N.D. Cent. Code. § 49-05-06, Subd. 2. A separate Alternate Petition for Interim Rates is submitted with this notice.

The rate and tariff changes would result in an annual increase of natural gas revenues of $1,280,232, or 1.8%, effective for natural gas usage on and after December 2, 2004, or upon final approval if the rates are suspended and interim

rates approved. The test year for the proposed increase is 2004. The rates and tariffs being revised are listed in Schedule 1 to this Notice. Schedules 2 and 3 contain the revised tariff sheets in regular and legislative formats, respectively. The proposed rates would affect the Company's service to all of its approximately 41,000 retail natural gas customers in the State of North Dakota.

For the convenience of the Commission and Staff, Schedule 4 provides a summary comparison of the proposed gas rates to the Company's present gas rates, and also gives the typical customer bill impacts by customer class and various usages. Schedule 5 shows the present and proposed revenues and the resulting revenue increase for each customer class, along with a comparison of the proposed revenues by customer class to the revenue deficiencies determined for each class in the Class Cost of Service Study.

A. Need for Rate Increase

Xcel Energy's present natural gas base distribution rates are essentially unchanged since the Commission approved a general increase for the Company's North Dakota customers in Case No. 10,523, order dated October 1, 1984.

In 1996, the Company decreased base distribution rates approximately $0.5 million (Case No. PU-400-95-559, order dated August 7, 1996). Base rates were restored to their pre-1996 level in 2001, when the Commission approved a base distribution rate increase of $0.5 million (in addition, a temporary Cost of Gas ("COG") surcharge -- $360,000 per year for eight years -- to recover the amortized costs of cleaning up the site of a former manufactured gas plant in

Grand Forks, North Dakota was also established).[1] See Case No. PU-400-00-521, order dated June 27, 2001.

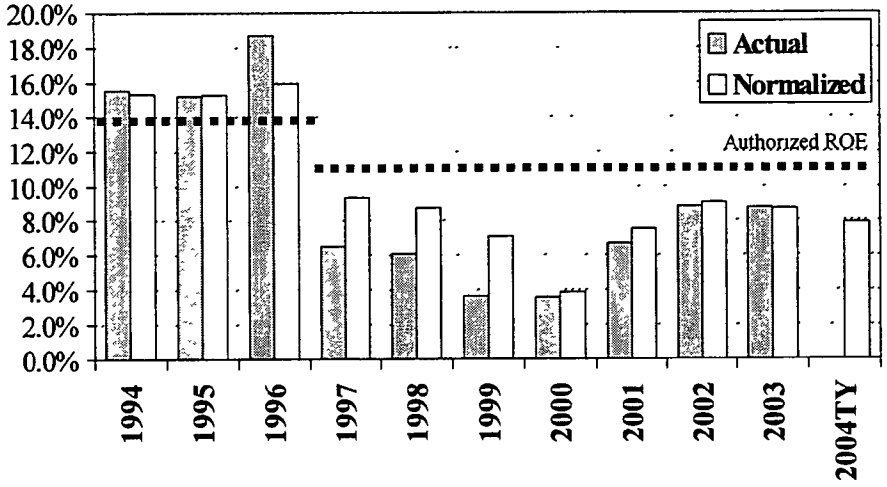
The current rate increase and tariff changes are needed to:

1) Recover the costs of expanding, upgrading, operating and maintaining the Company's North Dakota natural gas distribution system to meet the increasing natural gas service needs of customers in the cities of Fargo and Grand Forks and surrounding areas. Since the 2000 rate case, the Company's customer base in North Dakota has grown from 36,900 to 41,100, or 11.4%, and Xcel Energy has invested approximately $12.6 million in natural gas distribution plant and associated information and control system equipment attributable to North Dakota. These investments were made to continue to provide reliable, cost-effective and safe natural gas service in two of the state's largest communities.
2) While there has been a modest growth in the customer base, natural gas use per customer has declined approximately 2% annually as a result of appliance efficiencies, improved building materials and codes, and customer response to commodity gas price fluctuations. This has significantly offset the revenue gains resulting from customer growth, already weakened by the residual impacts of the 1997 Grand Forks flood. Hence, gas distribution revenues are insufficient to make up for the increased overall cost of providing service, including earning a reasonable return on investment.
3) Provide the Company with a reasonable return on equity ("ROE") for its North Dakota gas operations, to insure rates are just and reasonable. The Commission order in the 2000 rate case authorized an ROE of 11.5

[1] By comparison, the Company has filed natural gas general rate cases in the State of Minnesota jurisdiction in

percent. By contrast, the Company reported jurisdictional returns on equity of 6.67% for 2001, 8.79% for 2002, and 8.71% for 2003 for its natural gas distribution operations in North Dakota. The "weather normalized" returns for the same period were 7.53% in 2001, 9.04% in 2002 and 8.64% in 2003. Clearly, such returns cannot maintain the financial health of the Company on a long-term basis. The chart below shows the Company's earned returns for the previous ten years (actual ROE and ROE normalized for weather and purchased gas recovery timing are shown), and the significant deficiencies experienced since final rates were placed into effect in 2001.

ND Gas Return on Equity



* Normalized adjusted for weather and Cost of Gas recovery timing

It should be noted that while the above demonstrates the need for rate relief, Xcel Energy has been able to hold its operating and maintenance costs flat compared to the time of its last rate case in 2000. The filed increase is clearly

1985, 1986, 1992 and 1997. Xcel Energy also filed a $9.9 million gas rate increase on September 17, 2004.

being driven primarily by investment related costs associated with meeting growth in our service territory and the revenue erosion caused by declining use per customer.

B. Proposed Return on Equity

For the purposes of calculating proposed rates, the Company used an 11.5% ROE, the same ROE used by the Commission to set final rates in the Company's 2000 natural gas rate case (Case No. PU-400-00-521). Thus the Company does not propose a change from the ROE underlying its existing natural gas rates in North Dakota. The test year capital structure and cost of capital used to calculate the proposed rates is contained in Schedule 10.

C. Proposed Treatment of Unamortized Environmental Clean-up Costs

The Company proposes to include the unamortized balance of the costs incurred to clean up the former site of a manufactured gas plant ("MGP") in Grand Forks, ND. In 2000, Xcel Energy spent $3.2 million to remove contaminents from the site. In 2001, the Commission approved an eight year amortization of $2.9 million (the North Dakota jurisdictional allocation of the total cost) in Case No.PU-400-00-521. The Company was not allowed to recover any carrying costs associated with the expenditure. Approximately $1.8 million remains to be amortized, and the proposed tariffs reflect the inclusion of this balance in rate base. The annual amortization of $360,000 continues to be collected through an adjustment to the Cost of Gas factor and is not being included in base rates as part of this filing.

D. Proposed Cost Allocation and Rate Design

The Company allocated the rate increase among customer classes to reduce the interclass subsidies that exist in current rates. The proposed rates will more accurately recover the costs of service from the customers causing those costs to be incurred.

In addition, Xcel Energy is proposing to implement a "partial decoupling" bill adjustment to reduce the impact of the declining use per customer trend being experienced in the Company's gas distribution service territories.

The proposed rate changes effective December 2, 2004, if not suspended, do not affect recovery of the delivered cost of purchased commodity natural gas, which is separately reflected in retail rates through the Cost of Gas adjustment provisions of the Company's North Dakota Gas Rate Book.

Schedule 7 provides a more detailed narrative of the cost of service study, rate design methods used to develop the revised gas rates, and Schedule 8 summarizes the cost allocation methods used in the Class Cost of Service Study ("CCOSS").

E. The Proposed Rate Change Would Serve the Public Interest

Because the rate increase would allow the Company to recover its reasonable cost of service while minimizing both the subsidies between classes and the percentage increase to any customer class, the proposed rate increase does not unreasonably discriminate between the Company's customers or customer classes, and does not violate any Commission laws or rules. The proposed rates would thus serve the public interest and should be effective December 2, 2004, as proposed; in the alternative, the Commission should allow the Company to implement interim rates effective January 1, 2005, until final base rates are placed into effect.

II. REQUIRED FILING INFORMATION

A. Name and Address of Applicant

Pursuant to the Commission's "How to File" guidelines, the name and address of the public utility submitting this Notice is:

Northern States Power Company d/b/a Xcel Energy
Attn: Kent T. Larson
Vice President, Jurisdictional
414 Nicollet Mall – 5th Floor
Minneapolis, Minnesota 55401

Northern States Power Company d/b/a Xcel Energy is a wholly-owned subsidiary of Xcel Energy Inc., a registered holding company created by merger on August 18, 2000.[2] The North Dakota division office of Xcel Energy is located at:

Northern States Power Company d/b/a Xcel Energy
Attn: David H. Sederquist
Sr. Consultant, Regulation & Finance
2302 Great Northern Drive
Fargo, North Dakota 58102
Phone: (701) 241-8632
Fax: (701) 241-8682
Email: dave.sederquist@xcelenergy.com

In addition, the Company requests the following counsel be placed on the Commission's official service list for this proceeding:

[2] See "Findings of Fact, Conclusions of Law and Order," Case Nos. PU-400-99-418 and PU-400-98-246, Amended Order dated May 12, 2000.

James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc.
800 Nicollet Mall – Suite 2900
Minneapolis, MN 55401
Phone: (612) 215 4592
Fax: (612) 215-4544
Email: james.p.johnson@xcelenergy.com

B. Proposed Rates and Tariffs

Pursuant to N.D. Cent. Code § 49-05-05 and N.D. Admin. Code § 69-09-01-26, the Company is submitting the following schedules:

- Schedule 1 provides a summary list of the Gas Rate Book tariff sheets proposed to be changed;
- Schedule 2 provides the changed rates and tariffs proposed to be effective December 2, 2004, unless suspended and interim rates are put into effect;
- Schedule 3 shows the same tariff changes in "legislative" format, with new rates or tariff provisions underlined and deleted rate or provisions stricken;
- Schedule 4 summarizes present and proposed rates, and shows the typical bill impacts of the proposed increase for different customer classes and usages;
- Schedule 5 shows the present and proposed revenues and corresponding revenue increase for each customer class, along with a comparison of the proposed revenues compared to the CCOSS class revenue deficiencies;

In addition to the revised tariff sheets, typical bill impact information, and present and proposed revenues, the Company is also providing the following schedules that provide additional documentation in support of the Notice of Change in Rates:

- Schedule 6: 2004 Test Year Jurisdictional Cost of Service Study ("JCOSS");
- Schedule 7: Narrative of Cost of Service Study and Rate Design methodology;
- Schedule 8: Summary of Class Cost of Service Study allocation factors;
- Schedule 9: 2004 Test Year Class Cost of Service Study ("CCOSS")
- Schedule 10: Test Year Capital Structure and Cost of Capital
- Notice of Alternate Petition For Interim Rates, with rates becoming effective January 1, 2005, subject to refund, if the proposed rate change is suspended.

C. Filing Fee and Verification

Pursuant to N.D. Cent. Code § 49-05-05, Xcel Energy has prepaid the filing fee of $50.00 through its periodic regulatory fee payments to the Commission. Pursuant to the 1992 filing guidelines, also enclosed is the sworn affidavit of Kent T. Larson verifying the correctness of the Notice, proposed rate and tariff changes, and schedules hereto.

III. NOTICE TO AFFECTED CUSTOMERS

N.C. Cent. Code § 49-05-05 and Commission rules do not specifically require the Company to provide notice of the proposed gas rate change to customers.[3] However, if the Commission decides a written notification to customers would be appropriate to provide information about the proposed changes to customers, the Company would voluntarily include a customer information notice in bills to

[3] Compare N D. Admin. Code § 69-09-01-26 (Standards of Service – Gas) to § 69-09-02-02.1 (Standards of Service – Electric).

be issued to natural gas customers in North Dakota on and after December 2, 2004, if the rate increase is effective on the date proposed. The customer information notice would be distributed for one billing cycle and would describe the reasons for the rate changes. It would also provide information on how to contact the Company or the Commission with questions or comments about the changes. The Company would provide a sample notice for Staff and Commission review prior to mailing in customer bills, if the Commission so desires.

If the Commission suspends the proposed increase within 30 days and issues an order allowing the Company to place the interim gas rate increase in effect on January 1, 2005, subject to refund, the Company would voluntarily include a customer information notice in bills to be issued to natural gas customers in North Dakota on and after January 1, 2005, if the Commission decides a written notification to customers would be appropriate to provide information about the interim rate change to customers. Again, the customer information notice would be distributed for one billing cycle, would describe the reasons for the interim rate change, and would provide information on how to contact the Company or the Commission with questions or comments about the changes. The Company would provide a sample notice for Staff and Commission review prior to mailing in customer bills, if the Commission so desires.

IV. PROPOSED PROCEDURES

Pursuant to N.D. Cent. Code § 49-05-05, the Company respectfully requests the Commission allow the proposed rate and tariff changes shown in Schedules 1, 2, and 3 to be placed into effect December 2, 2004, without suspension or hearing. This Notice and schedules thereto fully satisfy the requirements for a Notice of Rate Changes effective December 2, 2004, subject to the Commission's authority to thereafter prospectively change such rates and tariffs through a final order under N. D. Cent. Code § 49-05-06 if the Commission formally investigates the change.

N.D. Cent. Code § 49-05-05 does not require the Company to submit expert pre-filed direct testimony in support of the various rate changes when submitting this Notice of Rate Change. If the Commission decides to conduct a hearing, the Company would submit pre-filed testimony pursuant to the procedural schedule established for the hearing. The testimony would simply support the information contained in this Petition and the supporting exhibits. This is the process used for the 2001 natural gas rate increase in Case No. PU-400-00-521. The Company is also receptive to working with Commission Staff to promptly resolve the proceeding through an information and settlement process similar to that used for the 2001 natural gas rate increase in Case No. PU-400-00-521.

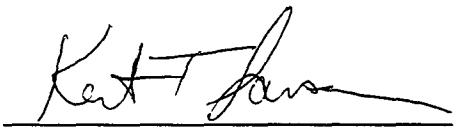
V. CONCLUSION

For the foregoing reasons, Northern States Power Company d/b/a Xcel Energy provides notice to the North Dakota Public Service Commission of new natural gas rates and tariffs to be effective December 2, 2004, pursuant to N. D. Cent. Code § 49-05-05 and N.D. Admin. Code 69-09-01-26. If the Commission suspends the proposed revised rates and tariffs within 30 days of this notice of

rate change, the Company requests the Commission to issue an order allowing the Company's proposed Interim Rates to be effective January 1, 2005, subject to refund, pursuant to N.D. Cent. Code § 49-05-06, Subd. 2 (see Alternative Petition for Interim Rates submitted with this filing).

Please direct any questions regarding this Notice of Change in Rates for Natural Gas Service and/or the Alternative Petition For Interim Rates to Mr. Dave Sederquist at (701) 241-8632 or Mr. Jim Johnson at (612) 215 4592.

Respectfully Submitted,

By: 

Kent T. Larson
Vice-President
Northern States Power Company d/b/a Xcel Energy

Date: November 2, 2004

Northern States Power Company d/b/a Xcel Energy
Gas Utility – State of North Dakota
Summary of Modified Tariffs

Rate Code	Description	Section	Sheet	Proposed Revision
---	Table of Contents	1	1	2
	" " " (to be deleted)	1	A	1
	" " " (" " ")	1	B	1
	" " " (" " ")	1	C	1
---	Contact List	2	1	2
---	Technical & Special Terms (to be deleted)	4	2	2
401	Residential Firm Service	5	1	4*
403, 410	Commercial & Industrial Firm Service	5	2	4*
404	Small Interruptible Service	5	3	3
	" " "	5	4	3*
405	Large Interruptible Service	5	5	3*
	" " "	5	6	3
407	Interruptible Transportation Service	5	8	3
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CONTACT LIST

Section No 2
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Listed below is the name, title, address, and telephone numbers of Company personnel to be contacted in connection with

All Matters Relating to Rates and Rules	Kent T Larson	T
	Vice President of Jurisdictional Relations	T
	Northern States Power Company, d/b/a Xcel Energy	T
	414 Nicollet Mall	T
	Minneapolis, MN 55401	T
	Telephone No 1-800-328-8226	T
Gas Emergencies and Outages	Telephone No (800) 895 2999	T
24-Hour Residential Customer Service	Telephone No. (800) 895-4999	T
Business Solutions Center	Telephone No. (800) 481-4700	T
(Business Customer Service)		T
TDD/TYY (Hearing Impaired Services)	Telephone No (800) 895-4949	N
Internet Address	www xcelenergy com	N

TECHNICAL AND SPECIAL TERMS (Continued)

Section No 4
2nd Revised Sheet No 2

CANCELED

RESIDENTIAL SERVICE
RATE CODE 401

Section No 5
4th Revised Sheet No 1

AVAILABILITY
This rate is available to any residential customer for domestic use of natural gas service

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	$8 50	C
Distribution Charge per Therm	$0.12388	C
Cost of Gas Charge per Therm	Determined Monthly	

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

ANNUAL DISTRIBUTION MARGIN ADJUSTMENT N
Bills are subject to the Annual Distribution Margin Adjustment in the Partial Decoupling Mechanism set forth on Sheets 5-63 and 5-64, effective June 1, 2006 through August 31, 2009 N N

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due.

COMMERCIAL AND INDUSTRIAL SERVICE
RATE CODE 403 AND 410

Section No 5
4th Revised Sheet No 2

AVAILABILITY
This rate is available to any commercial and industrial customer for general use of natural gas service T

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base T
pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T

RATE

Basic Service Charge per Month	$20.00	C
Distribution Charge per Therm	$0 10120	C
Cost of Gas Charge per Therm	Determined Monthly	

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

MONTHLY MINIMUM CHARGE
Basic Service Charge.

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.

LATE PAYMENT CHARGE
A 1.0% late payment charge will be added to the unpaid balance on date due

SMALL INTERRUPTIBLE SERVICE
RATE CODE 404

Section No 5
3rd Revised Sheet No 3

AVAILABILITY

This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are less than 2,000 Therms, and who will agree: T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit. T T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

RATE

Basic Service Charge per Month	$75 00	C
Distribution Charge per Therm	$0 07740	C
Cost of Gas Charge per Therm	Determined Monthly	

DETERMINATION OF COST OF GAS

Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations. The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider. T

(Continued on Sheet No 5-4)

SMALL INTERRUPTIBLE SERVICE (Continued)
RATE CODE 404

Section No 5
3rd Revised Sheet No 4

MONTHLY MINIMUM CHARGE
Basic Service Charge.

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so.

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No 5
5th Revised Sheet No 5

AVAILABILITY

This rate is available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree T

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion. If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit. T T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$275 00	C
Distribution Charge per Therm	$0 04632	C
Cost of Gas Charge per Therm	Determined Monthly	

(Continued on Sheet No. 5-6)

LARGE INTERRUPTIBLE SERVICE (Continued) Section No 5
RATE CODE 405 3rd Revised Sheet No 6

Flexible Distribution Charge
Customers are normally served on the fixed rate but will be placed on the flexible rate if, for pricing reasons, the flexible rate is necessary to compete with a non-gas alternate energy supply/service Company and customer will agree to a price between $0 00600 and $0 04390 per Therm. Unless otherwise agreed, a five day notice of price change shall be provided If Company and customer cannot agree to a flexible distribution charge and customer nonetheless uses gas, then customer shall be charged the maximum allowable flexible distribution charge

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations. The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Cost of Gas Rider T

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so.

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority. Curtailment shall begin with Priority 8 and progress to Priority 1. Priority classifications are defined in the General Rules and Regulations.

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party

INTERRUPTIBLE TRANSPORTATION SERVICE
RATE CODE 407

Section No. 5
3rd Revised Sheet No 8

AVAILABILITY

This rate is available on an interruptible basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station, whose maximum daily requirements are more than 2,000 Therms, and who agrees· T

1 To curtail use of gas within one hour after Company notification,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment in the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option.

CHARACTER OF SERVICE

Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed. Delivery of gas hereunder shall be subject to curtailment whenever requested by Company Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption i adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month $300 00

	Minimum	Maximum
Distribution Charge per Therm	$0 0060	$0 04390

Unless otherwise agreed to between customer and Company, five days notice of price change shall be provided.

(Continued on Sheet No 5-9)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
3rd Revised Sheet No 10

MONTHLY MINIMUM CHARGE
Unless otherwise agreed to in a negotiated service contract, the monthly minimum is the Basic Service Charge

NOMINATIONS
Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a.m. CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11.30 a m
Evening	6 00 p m
Intra-day 1	10 00 a m
Intra-day 2	5:00 p m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional. Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules. EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p.m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS
Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation. The net daily variance will be assessed a penalty of $0 05 per Therm. However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism. The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor. Monthly imbalances will not be carried forward to the next calendar month

(Continued on Sheet No 5-10 1)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10.1

MONTHLY UNDERTAKE / OVERTAKE CHARGE Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate. The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point. ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively. C

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1.00 + ITC	MIP * 1 00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0 98 + FTC
>5% - 10%	MIP * 1.10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1 30 + ITC	MIP * 0.70 + FTC
>20%	MIP * 1 40 + ITC	MIP * 0.60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to: GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis C

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.

LATE PAYMENT CHARGE
A 1% late payment charge will be added to the unpaid balance on date due.

(Continued on Sheet No 5-10.2)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10.2

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration.

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers. Rules and regulations defining Company's obligation are set out in Section 6 of this rate book

ADDITIONAL FACILITIES

The cost of any new facilities required to provide service under this rate shall be borne by the customer.

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located. Company may refuse to accept delivery of gas that does not meet this quality standard T

EMERGENCY GAS SERVICE FOR INTERRUPTIBLE CUSTOMERS

Section No 5
2nd Revised Sheet No. 11

AVAILABILITY

This rate is available to an interruptible customer for supply of emergency gas during periods of curtailment when a customer is unable to operate its standby facilities for causes not reasonably within its control T

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

RATE

Operational Cost per Therm	$0.13468	DN
Cost of Propane Gas per Therm	$0 71415	N
Total Cost per Therm	$0 84883	NT

DETERMINATION OF COST OF GAS

If the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference C C

DISTRIBUTION CHARGE

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

SPECIAL TERMS AND CONDITIONS

1. Emergency gas service will be available providing that
   a A customer has advised the Company that it is experiencing an emergency and, in the opinion of Company, it is an emergency resulting from causes not reasonably within customer's control Failure of the customer to take normal precautions for providing its alternate fuel supply will not be considered an emergency T T
   b Customer shall make arrangements with Company specifying the reason for said service and the probable duration of the emergency
   c. Such service will not adversely affect firm service to any customer

2 Customer receiving emergency service shall agree in writing as to the quantity of gas to be supplied and the duration of the service Gas used prior to the effective date and time agreed to will be billed under the provision "Additional Charge for Use of Gas During Curtailment" of the applicable interruptible rate. T

3 The Company reserves the right to refuse or curtail the supply of emergency gas service if its supply of gas is not adequate to furnish such service

4. All other provisions of the interruptible service rate schedules not in conflict herewith shall apply

GAS YARD LIGHTING SERVICE (CLOSED)
RATE CODE 408

Section No. 5
2nd Revised Sheet No. 12

CANCELED

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE
RATE CODE 415

Section No. 5
3rd Revised Sheet No. 13

AVAILABILITY
This rate is available on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms T

CHARACTER OF SERVICE
Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit. T T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Customer Charge per Month	$300 00	
	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0 69600
Energy Charge per Therm	$0.00898	$0.03471

Unless otherwise agreed to, a five-day notice of any change in the energy charge shall be provided T

RESOURCE ADJUSTMENT
Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider. The Company will revise the surcharge annually on the effective date of the True-up factor change

(Continued on Sheet No. 5-13 1)

FIRM TRANSPORTATION SERVICE (Continued)
RATE CODE 415

Section No. 5
Original Sheet No. 13.2

NOMINATIONS

Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT. Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6.00 p m.
Intra-day 1	10:00 a m.
Intra-day 2	5:00 p m.

The Timely and Evening nominations are prior to the start of a Gas Day. The Timely nomination is mandatory. The remaining three nomination times are optional. Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination. EPSQ rules divide a daily nomination into 24 hourly increments. Intra-day 1 nominations may not be less than sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS

Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties. The net daily variance will be determined by comparing customer's actual metered use with the volume nominated. The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0.05 per Therm. However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination.

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month

(Continued on Sheet No 5-13 3)

FIRM TRANSPORTATION SERVICE (Continued)
RATE CODE 415

Section No 5
1st Revised Sheet No 13 3

MONTHLY UNDERTAKE / OVERTAKE CHARGE C

Customer using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake to Company at the applicable undertake rate Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1 00 + ITC	MIP * 1.00 + FTC
>3% - 5%	MIP * 1 02 + ITC	MIP * 0.98 + FTC
>5% - 10%	MIP * 1 10 + ITC	MIP * 0 90 + FTC
>10% - 15%	MIP * 1 20 + ITC	MIP * 0 80 + FTC
>15% - 20%	MIP * 1.30 + ITC	MIP * 0 70 + FTC
>20%	MIP * 1.40 + ITC	MIP * 0 60 + FTC

The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to: GTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise. However, Company will treat similarly situated customers on a non-discriminatory basis C

LATE PAYMENT CHARGE
A 1% late payment charge will be added to the unpaid balance on due date

SURCHARGE
Bills are subject to the applicable surcharge provided for in the Surcharge Rider.

(Continued on Sheet No 5-13 4)

STANDBY SERVICE RIDER

Section No 5
2nd Revised Sheet No 24

CANCELED

(Continued on Sheet No. 5-25)

STANDBY SERVICE RIDER (Continued)

Section No. 5
Original Sheet No. 25

CANCELED

LIMITED FIRM SERVICE RIDER

Section No. 5
1st Revised Sheet No. 26

AVAILABILITY
This rate is available to any Interruptible or Interruptible Transportation Service customer who, when subject to interruption or curtailment, desires to supplement its service by reserving a specified number of days of firm gas service in a Limited Firm Service Agreement with Company Limited Firm Service will be restricted to 10 days for Small Volume customers and 15 days for Large Volume customers during the term of agreement T

CHARACTER OF SERVICE
Company in its sole discretion may decline to enter into Limited Firm Service Agreements or limit the days of availability and shall consider the Company's estimate of its distribution capacity and stored gas availability to provide Limited Firm Service

CURTAILMENT
If the Company's system operations require curtailment of firm service, service hereunder will be curtailed before all other firm service, and customer will be credited a portion of the Availability Charge based on the days of curtailed firm service and that contracted for.

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit T T

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

COST OF PROPANE GAS RATE
Availability Charge As specified in the Limited Firm Service Agreement between customer and Company

Operational Cost per Therm	$0 13468	C
Cost of Propane Gas per Therm	$0 71415	C
Total Cost per Therm	$0 84883	C

DETERMINATION OF COST OF GAS
f the Company's average inventory propane cost for this rider differs from $0 64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1 1 times the difference C C

DISTRIBUTION CHARGE N
All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate. N

(Continued on Sheet No 5-27)

PARTIAL DECOUPLING RIDER

Section No 5
Original Sheet No 28

APPLICABILITY N

This rider applies to all Residential customers.

ADJUSTMENT TO RATE SCHEDULE

Effective September 1, 2006
The adjustment for Residential customers is $0 00000 per Therm

DEFINITIONS

For the purposes of this tariff, the following definitions apply

Monthly Weather Normalized Use Per Customer = weather-normalized actual sales for the Residential class during the month divided by the actual number of Residential customers during the same month The weather-normalized actual sales for the Residential class will be calculated using the same approach to weather normalization established in the Company's last general rate case (Docket No PU-400-04-578)

Monthly Test Year Use Per Customer = Residential use per customer for the month approved or used by the Commission to derive Residential rates in the Company's last general rate case (Docket No. PU-400-04-578)

Residential Distribution Rate Per Therm = Residential Distribution Charge per Therm effective during the month under the provisions of the Residential Firm Service tariff.

Monthly Test Year Customers = number of Residential customers for the month approved or used by the Commission to derive Residential rates in the Company's last general rate case (Docket No PU-400-04-578).

Annual Carrying Charge = before-tax weighted cost of capital approved by the Commission in the Company's last general rate case X the balance in the Monthly Distribution Margin Differentials subaccount as of June 30.

Annual Rate Adjustment Per Therm = Annual Distribution Margin Differential Adjustment / projected Residential use in therms from September 1 of the year in which the Annual Distribution Margin Differential Adjustment was calculated through August 31 of the following year

PARTIAL DECOUPLING DEFERRAL ACCOUNT

1. Each month for the Residential class the Company will calculate the difference between the Monthly Weather Normalized Use Per Customer and the Monthly Test Year Use Per Customer The resulting difference shall be multiplied by the Residential Distribution Charge Per Therm effective during that month and by the Monthly Test Year Customers. The resulting product will be the Monthly Distribution Margin Differential N

PARTIAL DECOUPLING RIDER (Continued)

Section No 5
Original Sheet No 29

PARTIAL DECOUPLING DEFERRAL ACCOUNT (Continued)

N

2 The Company will defer and amortize the Monthly Distribution Margin Differentials in a subaccount of Account 186. Each year on June 30 an Annual Carrying Charge will be added to the balance in this subaccount to yield the Annual Distribution Margin Differential Adjustment

Partial Decoupling Rate Adjustment

1. Each year during the term of this rider the Company will calculate an Annual Rate Adjustment Per Therm This adjustment will be applied to Residential bills from September 1 through August 31 and will be implemented through a revised Residential Energy Charge through a revision to Rate Schedule 5-1. The revised Residential Energy Charge will equal the base Energy Charge approved by the Commission in Docket No PU-400-04-xxx plus the applicable Partial Decoupling Rate Adjustment

2 The Company shall file by September 1 of each year its determination of the Annual Rate Adjustment Per Therm with all supporting information used to determine this rate adjustment This filing shall include the revised Residential and Partial Decoupling Rate Adjustment tariffs needed to implement the applicable rates.

3 Any under- or over-recovery of the Annual Distribution Margin Differential Adjustment will be included as a deferral in the Monthly Distribution Margin Differentials subaccount and reflected in the calculation of the following year's Annual Rate Adjustment Per Therm

SUNSET DATE

This mechanism shall allow for three annual partial decoupling rate adjustments Customers' bill shall be adjusted through the August 2009 billing month. This tariff terminates September 1, 2009

N

3.6 BILL DATE DUE

Bills are due and payable upon presentation For purposes of applying the late payment charge, the date due shown on the customer's bill shall be

Class	Date Due
Interruptible	Minimum of 10 working days after bill mailing date
All Other Classes	Next scheduled billing date minus four working days

3.7 ESTIMATED BILLS

An estimated bill will be rendered if it is impractical for the Company to read the meter or if customer fails to supply a meter reading form in time for the billing operation, or in cases of emergency An adjustment, if any, will be made in the bill based on the next meter reading

3.8 BILLING ADJUSTMENTS

In the event of a meter or billing error, as defined by the Public Service Commission's rules, the Company shall recalculate the bills for service during the period of the error and make adjustment of bills in accordance with the rules prescribed by the Commission. If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10.00

3.9 RETURNED CHECK CHARGE

There shall be a charge of $25 00 for any check or draft submitted to the Company for payment that is dishonored or returned by the financial institution on which it is drawn T

3.10 ACCOUNT HISTORY CHARGE

There shall be a charge of $0.50 per account to the authorized requesting party for providing account history when such request involves 10 or more accounts, regardless of the type of account or number of meters An authorized requesting party may be the customer, a person authorized by the customer, or a person authorized by law to receive the requested information

5.2 MAIN EXTENSIONS

The Company will extend, enlarge, or change its gas mains or other facilities for supplying gas service when the anticipated revenue from the sale of additional service to result therefrom is such as to justify the expenditure When the expenditure is not so justified, the extension, enlargement, or change of facilities will be made only if the customer, at the Company's option.

A. Pays in advance to the Company in cash for the additional installation costs for excess footage as required by the Company's current footage costs or by promissory note acceptable to the Company, the portion of the capital expenditure not justified by the anticipated annual revenue with provision for refund of all or part of such payment, C

B. Agrees to pay a special monthly charge,

C Agrees to pay annually a specified minimum charge, or

D Agrees to a combination of the above methods

In addition, a non-refundable payment in advance must be made covering the specified additional cost of any unusual construction

For each additional customer served directly from the main extension within five years from the date of its completion, the person who made advance payment will receive refunds based on the revenue to be received from the additional customers served from the extension and the costs required to serve such customers The total of such refunds will in no event exceed the total advance payment No refunds will be made for additional customers served by additional main extensions connected at any point to the first customer's original extension

For trailer parks, the Company will only extend its gas main to a delivery point at a permanent structure which houses facilities such as offices or laundry facilities It shall be the trailer park owner's responsibility to extend the distribution system to individual trailer sites.

D

(Continued on Sheet No 6-19)

GENERAL RULES AND REGULATIONS (Continued)

Section No 6
1st Revised Sheet No 19

5.3 WINTER CONSTRUCTION

When the service or main is installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30 or because the customer's property, or the streets leading thereto, are not ready to receive the service pipe or gas main by such date, such work will be subject to a winter construction charge when winter conditions of ground frost and/or snow exist, for the entire length of underground service or gas main installed Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install gas main or gas service pipe during the winter season The charges immediately below apply to frost depths of 18" or less. At greater frost depths, the Company will individually determine the job cost The Company reserves the right to charge for any unusual winter construction expenses All winter construction charges are non-refundable and are in addition to any normal construction charges C

Winter Construction Charge		
Excavation		$400 per excavating unit
Main & Service Extensions	4 Inch or Under Pipe	$3 00 per foot
	Over 4 Inch Pipe	Determined Individually

C

5.4 LIMITATIONS ON THE AVAILABILITY OF GAS

New and existing customers requiring service for new or increased firm or interruptible gas loads must make an application for such service The Company shall apply the applicable limitations set forth in this section in determining whether to approve an application. When supplies of gas and distribution capacity are adequate, Company will authorize connection of qualifying customers in the order that their application is received When an applicant is one for which a main extension is required, the application will be held until the main extension is approved, at which time it shall be processed the same as an on-main customer

A New and Existing Firm Customers

1 New customers will be added in accordance with Section 5, EXTENSION RULES, of the General Rules and Regulations

2 Existing loads, except as noted below, may be increased and new loads added only with the approval of the Company based upon the adequacy of gas supplies and gas distribution capacity

3 Increases in existing loads for non-heating requirements not in excess of 0 5 Therm per hour do not require Company approval in accordance with Section 1.1, APPLICATION FOR SERVICE, of the General Rules and Regulations

(Continued on Sheet No 6-20)

GENERAL RULES AND REGULATIONS (Continued)

Section No. 6
1st Revised Sheet No 22

5.5 SERVICE CONNECTIONS (Continued)

In addition, the Company will, at its own expense for all customers, furnish and install piping for a distance not to exceed five feet for

A Indoor Metering
From the service to the meter header or meter yoke

B Outdoor Metering
From the end of the horizontal service pipe to the outside of the customer's building wall.

If this distance exceeds five feet in length, the Company will extend the piping if the customer will share the cost based on the Company's current footage costs C D

5.6 TEMPORARY SERVICE

The following special requirement is prescribed to govern temporary service

A customer taking temporary service (less than five years) will pay the rate applicable to the class of service rendered and will pay in advance the Company's specified cost, figured on a time and material basis, of the installation and removal of the facilities, including the meter required to furnish the desired service, less the salvage value of such facilities.

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	Surcharge Rider	5-21	
	Daily Balancing Service Rider	5-22	N
	~~Standby Service Rider~~	~~5-24~~	ND
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		G 4	1st
	4-2	N/A	
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Residential Service	5-1	G 5	9th
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	5-4	G 11	15th
		G 12	11th
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	5-9	G 15	10th
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N/A - Not applicable

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(Continued)

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CANCELED

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	6-5 RFU	N/A	
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	6-7	G 26	3rd
		G 27	4th
	6-8 RFU	N/A	

N/A - Not applicable
RFU - Reserved for future use

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1st Revised Sheet No C

CANCELED

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	6-26	G 35	5th
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N/A - Not applicable
RFU - Reserved for future use

CONTACT LIST

Section No 2
2nd Revised Sheet No. 1

Listed below is the name, title, address, and telephone numbers of Company personnel to be contacted in connection with:

All Matters Relating to Rates and Rules	~~Michael L. Swenson~~Kent T. Larson ~~State Vice President~~Vice President of Jurisdictional Relations ~~North Dakota and South Dakota~~ Northern States Power Company, d/b/a Xcel Energy ~~2302 Great Northern Drive~~414 Nicollet Mall ~~Fargo, North Dakota 58102~~ Minneapolis, MN 55401 Telephone No ~~(701) 241-8607~~1-800-328-8226	T T T T I I I
Gas Emergencies and Outages	Telephone No (800) 895 2999	T
24-Hour Residential Customer Service	Telephone No (800) 895-4999	T
Business Solutions Center (Business Customer Service)	Telephone No (800) 481-4700	T I
TDD/TYY (Hearing Impaired Services)	Telephone No. (800) 895-4949	N
Internet Address	www.xcelenergy.com	N

TECHNICAL AND SPECIAL TERMS (Continued)

Section No 4
2nd Revised Sheet No 2

CANCELED

~~SUBDIVISION 3 — RATE CODES~~

~~Rate Schedule~~	~~CSS Code~~	~~Cancels Prior Rate Code~~				
~~Residential Service~~	~~401~~	~~1B641~~	~~1H641~~			
~~Commercial and Industrial Service~~	~~403~~	~~3B641~~	~~3H641~~	~~3L641~~		
~~Small Interruptible Service~~	~~404~~	~~31149~~	~~31249~~			
~~Large Interruptible Service~~	~~405~~	~~51149~~ ~~51449~~ ~~51549~~	~~52049~~ ~~53049~~ ~~54049~~	~~55049~~ ~~56049~~ ~~57049~~	~~58049~~	
~~Interruptible Contract Service~~	~~406~~	~~30040~~	~~50040~~			
~~Interruptible Transportation Service~~	~~407~~	~~None~~				
~~Emergency Gas Service for Interruptible Customers~~	~~—~~	~~39149~~	~~59149~~			
~~Gas Yard Lighting Service (Closed)~~	~~408~~	~~1B048~~				
~~Firm Transportation Service~~	~~415~~					N
~~Propane Service (Non-Regulated)~~	~~409~~	~~1H543~~	~~3H543~~			
~~Daily Balancing Service Rider~~	~~—~~					N
~~Standby Service Rider~~	~~—~~					|
~~Limited Firm Service Rider~~	~~—~~					N

RESIDENTIAL SERVICE
RATE CODE 401

Section No. 5
4th Revised Sheet No. 1

AVAILABILITY
This rate is a~~A~~vailable to any residential customer for domestic use of natural gas service

THERM ADJUSTMENT
Customer's Therm usage shall equal their Ccf consumption ~~will be~~ adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	~~$5.50~~ $8.50	~~C~~C
Distribution Charge per Therm	~~$0.12480~~ $0.12388	~~C~~C
Cost of Gas Charge per Therm	Determined Monthly	~~N~~

DETERMINATION OF COST OF GAS ~~T~~
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations. The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the ~~Purchased~~ Cost of Gas Rider~~Adjustment Clause~~ ~~T~~T

ANNUAL DISTRIBUTION MARGIN ADJUSTMENT N
Bills are subject to the Annual Distribution Margin Adjustment in the Partial Decoupling Mechanism set forth on Sheets 5-63 and 5-64, effective June 1, 2006 through August 31, 2009. N N

MONTHLY MINIMUM CHARGE
Basic Service Charge ~~T~~

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider ~~T~~

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

COMMERCIAL AND INDUSTRIAL SERVICE
RATE CODE 403 AND 410

Section No. 5
4th Revised Sheet No. 2

AVAILABILITY

This rate is aAvailable to any commercial and industrial customer for general use of natural gas service I

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~will be~~ adjusted to reflect 1,000 Btu per cubic foot, I
a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit I

RATE

Basic Service Charge per Month	~~$14 00~~ $20.00	~~C~~C
Distribution Charge per Therm	~~$0 11280~~ $0.10120	~~C~~C
Cost of Gas Charge per Therm	Determined Monthly	~~N~~

DETERMINATION OF COST OF GAS

~~I~~
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the ~~Purchased~~ Cost of Gas Rider~~Adjustment Clause~~. ~~I~~I

MONTHLY MINIMUM CHARGE

Basic Service Charge ~~I~~

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider. ~~I~~

LATE PAYMENT CHARGE

A 1.0% late payment charge will be added to the unpaid balance on date due

SMALL INTERRUPTIBLE SERVICE
RATE CODE 404

Section No 5
3rd Revised Sheet No 3

AVAILABILITY

This rate is aAvailable on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are less than 2,000 Therms, and who will agree I

1. To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply. However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~will be~~ adjusted to reflect 1,000 Btu per cubic foot, I
a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit I

SUPERCOMPRESSIBILITY ADJUSTMENT ~~M~~

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility ~~M~~ ~~M~~

RATE

Basic Service Charge per Month	$75.00	~~C~~C
Distribution Charge per Therm	~~$0 07310~~ $0.07740	~~C~~C
Cost of Gas Charge per Therm	Determined Monthly	~~N~~

DETERMINATION OF COST OF GAS ~~T~~

Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations. The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the ~~Purchased~~ Cost of Gas RiderAdjustment ~~Clause~~ ~~T~~I

(Continued on Sheet No 5-4)

SMALL INTERRUPTIBLE SERVICE (Continued)
RATE CODE 404

Section No. 5
3rd Revised Sheet No. 4

MONTHLY MINIMUM CHARGE ~~M~~
Basic Service Charge ~~MT~~

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so.

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider. ~~T~~

LATE PAYMENT CHARGE
A 1.0% late payment charge will be added to the unpaid balance on date due.

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party.

LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No 5
5th Revised Sheet No. 5

AVAILABILITY

This rate is a~~A~~vailable on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree I

1 To curtail use of gas whenever requested by Company,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder.

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible.

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~will be~~ adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit I I

SUPERCOMPRESSIBILITY ADJUSTMENT ~~M~~

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility. ~~M~~ ~~M~~

RATE

Basic Service Charge per Month	$275 00	~~C~~C
Distribution Charge per Therm	~~$0 04390~~ $0.04632	~~C~~C
Cost of Gas Charge per Therm	Determined Monthly	~~N~~

(Continued on Sheet No 5-6)

LARGE INTERRUPTIBLE SERVICE (Continued)
RATE CODE 405

Section No 5
3rd Revised Sheet No. 6

Flexible Distribution Charge

MT

Customers are normally served on the fixed rate but will be placed on the flexible rate if, for pricing reasons, the flexible rate is necessary to compete with a non-gas alternate energy supply/service. Company and customer will agree to a price between $0 00600 and $0 04390 per Therm. Unless otherwise agreed, a five day notice of price change shall be provided If Company and customer cannot agree to a flexible distribution charge and customer nonetheless uses gas, then customer shall be charged the maximum allowable flexible distribution charge

MT

DETERMINATION OF COST OF GAS

T

Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the ~~Purchased Gas Adjustment Clause~~Cost of Gas Rider

TI

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT

If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

MONTHLY MINIMUM CHARGE

Basic Service Charge

T

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.

T

LATE PAYMENT CHARGE

A 1 0% late payment charge will be added to the unpaid balance on date due.

PRIORITY CLASSIFICATION

Priority 1 shall have first priority. Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations.

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party.

INTERRUPTIBLE TRANSPORTATION SERVICE
RATE CODE 407

Section No 5
3rd Revised Sheet No. 8

AVAILABILITY

This rate is a~~A~~vailable on an interruptible basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station, whose maximum daily requirements are more than 2,000 Therms, and who agrees· I

1 To curtail use of gas within one hour after Company notification,
2 To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment in the delivery of gas sold hereunder.

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion. If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE

Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed. Delivery of gas hereunder shall be subject to curtailment whenever requested by Company. Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~in Ccf will be~~ adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit I I

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$300 00		~~I~~
	Minimum	Maximum	
Distribution Charge per Therm	$0 0060	$0.04390	~~C~~

Unless otherwise agreed to between customer and Company, five days notice of price change shall be provided.

(Continued on Sheet No 5-9)

LARGE COMMERCIAL INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No. 5
3rd Revised Sheet No 10

MONTHLY MINIMUM CHARGE M

Unless otherwise agreed to in a negotiated service contract, the monthly minimum is the Basic Service Charge. M

NOMINATIONS

Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9 00 a m CCT Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a.m
Evening	6 00 p.m
Intra-day 1	10 00 a m.
Intra-day 2	5 00 p.m

The Timely and Evening nominations are prior to the start of a Gas Day. The Timely nomination is mandatory. The remaining three nomination times are optional Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules. EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination. EPSQ rules divide a daily nomination into 24 hourly increments Intra-day 1 nominations may not be less than ~~eight~~sixteen hours of C prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p.m). Company reserves the right to refuse nominations to maintain balance of its system

IMBALANCE PROVISIONS

Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties. The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5%. If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0.05 per Therm. However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination.

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor. Monthly imbalances will not be carried forward to the next calendar month.

(Continued on Sheet No. 5-10 1)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No. 5
2nd Revised Sheet No 10 1

MONTHLY UNDERTAKE / OVERTAKE ~~PURCHASE PAYMENT~~ CHARGE C

Customers ~~who use~~using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake ~~gas to~~ Company ~~–~~ at the applicable undertake rate. Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate. ~~Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate~~ The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point. ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively.

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1.00 + ITC	MIP * 1.00 + FTC
>3% - 5%	MIP * 1.02 + ITC	MIP * 0.98 + FTC
>5% - 10%	MIP * 1.10 + ITC	MIP * 0.90 + FTC
>10% - 15%	MIP * 1.20 + ITC	MIP * 0.80 + FTC
>15% - 20%	MIP * 1.30 + ITC	MIP * 0.70 + FTC
>20%	MIP * 1.40 + ITC	MIP * 0.60 + FTC

~~Monthly Imbalance %~~	~~Undertake Purchase Rate~~
~~100% to 98%~~	~~Index + Applicable Pipeline Firm Transportation Commodity rate(s)~~
~~98% to 90%~~	~~[Index + Applicable Pipeline Firm Transportation Commodity rate(s)] x 0 75~~
~~Less than 90%~~	~~[Index + Applicable Pipeline Firm Transportation Commodity rate(s)] x 0 50~~

~~The index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation)~~ –The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to ~~GRI~~I surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis C

(Continued on Sheet No 5-10 2)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10 1

D

~~**OVERTAKE CHARGE**~~

~~Customers who use more gas than the volume customer nominated and delivered to the Company system agree to purchase the overtake gas from Company. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.~~

~~Monthly Imbalance %~~	~~Overtake Rate~~
~~100% to 102%~~	~~Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)~~
~~102% to 110%~~	~~[Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)] x 1.25~~
~~Greater than 110%~~	~~[Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)] x 1.50~~

~~The index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to: GRI surcharge, ACA surcharge, fuel costs and interruptible transportation commodity charge. All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise. However, Company will treat similarly situated customers on a non-discriminatory basis.~~

D

T

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE

A 1% late payment charge will be added to the unpaid balance on date due.

(Continued on Sheet No 5-10 2)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
2nd Revised Sheet No 10 2

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION M C

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so. C

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration M

TERM OF AGREEMENT N

Service agreement shall be for a term of not less than one year. Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party.

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers Rules and regulations defining Company's obligation are set out in Section 6 of this rate book N

ADDITIONAL FACILITIES M

The cost of any new facilities required to provide service under this rate shall be borne by the customer

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located Company may refuse to accept delivery of gas ~~which~~that does not meet this quality standard M~~I~~

EMERGENCY GAS SERVICE FOR INTERRUPTIBLE CUSTOMERS

Section No 5
2nd Revised Sheet No 11

AVAILABILITY

This rate is ~~a~~Available to an interruptible customer for supply of emergency gas during periods of curtailment when a customer is unable to operate ~~his~~its standby facilities for causes not reasonably within ~~his~~its control I I

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~will be~~ adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit I I

RATE

~~Distribution Charge per Therm~~	~~$0.11280~~	~~C~~D
~~Cost of Gas Charge per Therm~~	~~see below~~	~~N~~D
Operational Cost per Therm	$0.13468	N
Cost of Propane Gas per Therm	$0.71415	~~I~~N
Total Cost per Therm	$0.84883	~~N~~N ~~N~~

DETERMINATION OF COST OF GAS

~~The Cost of Gas Charge per Therm shall be based on the current replacement cost of propane. The Cost of Gas shall be equal to $ 0110 per therm for each $ 0100 of the cost per gallon of replacement propane.~~ If the Company's average inventory propane cost for this rider differs from $0.64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1.1 times the difference. ~~I~~ I C I

DISTRIBUTION CHARGE C

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate. C

SURCHARGE

In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.

SPECIAL TERMS AND CONDITIONS

1 Emergency gas service will be available providing that:

a A customer has advised the Company that ~~he~~it is experiencing an emergency and, in the opinion of Company, it is an emergency resulting from causes not reasonably within customer's control. Failure of the customer to take normal precautions for providing ~~his~~its alternate fuel supply will not be considered an emergency I I

b Customer shall make arrangements with Company specifying the reason for said service and the probable duration of the emergency

c. Such service will not adversely affect firm service to any customer.

2 Customer receiving emergency service shall agree in writing as to the quantity of gas to be supplied and the duration of the service Gas used prior to the effective date and time agreed to will be billed under the

EMERGENCY GAS SERVICE FOR INTERRUPTIBLE CUSTOMERS

Section No. 5
2nd Revised Sheet No. 11

provision "Additional Charge for Use of Gas During Curtailment" of the applicable interruptible ~~service~~ rate ~~schedule~~ I I

3 The Company reserves the right to refuse or curtail the supply of emergency gas service if its supply of gas is not adequate to furnish such service.

4 All other provisions of the interruptible service rate schedules not in conflict herewith shall apply.

GAS YARD LIGHTING SERVICE (CLOSED)
RATE CODE 408

Section No. 5
2nd Revised Sheet No 12

CANCELED

~~**AVAILABILITY**~~

~~Available to a residential customer for service to an unmetered gas yard lighting installation when such service was being taken hereunder on December 1, 1973, and continuously thereafter and where gas service is being used at the same location for other purposes. Service under this schedule will not be available to new installations after December 1, 1973. Metered gas yard lighting will be billed on the applicable rate schedule.~~ T

~~**RATE**~~

~~Per Lamp per Month~~	~~$7.00~~	C
~~Cost of Gas Charge per Therm~~	~~Determined Monthly~~	N

~~**DETERMINATION OF COST OF GAS**~~ T

~~Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations. The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause. The monthly Cost of Gas Charge for this service will be the Purchased Gas Adjustment factor for residential service multiplied by 13.~~ T

~~**SURCHARGE**~~

~~In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.~~ T

~~**LATE PAYMENT CHARGE**~~

~~A 1.0% late payment charge will be added to the unpaid balance on date due.~~

~~**SPECIAL TERMS AND CONDITIONS**~~

~~1. Customer shall pay for the entire cost of installation including the piping from the service to the yard light. Company shall own and maintain the piping from the service to the yard light. Customer shall own and maintain the yard light.~~

~~2. The gas lamp may be either a single or double mantle installation.~~

~~3. The orifice will be sized to a #71 drill size.~~

~~4. Pressure will be set at four inches water column.~~

~~5. Yard lights with larger orifices or pressures higher than four inches water column will not be permitted on this rate schedule.~~

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE
RATE CODE 415

Section No 5
3rd Revised Sheet No 13

AVAILABILITY

This rate is aAvailable on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms

CHARACTER OF SERVICE

Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.

RATE

Customer Charge per Month	$300 00	
	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0 69600
Energy Charge per Therm	$0 00898	$0 03471

Unless otherwise agreed to, a five-day notice of any change in the energy charge shall be provided.

RESOURCE ADJUSTMENT

Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider The Company will revise the surcharge annually on the effective date of the True-up factor change.

(Continued on Sheet No 5-13.1)

FIRM TRANSPORTATION SERVICE (Continued)
RATE CODE 415

Section No 5
Original Sheet No 13 2

NOMINATIONS N

Customer shall, on a daily basis, advise Company's gas dispatcher in St Paul of the volume customer will request to be delivered during the following gas day commencing at 9:00 a m. CCT. Customer shall submit nominations to Company at least two hours in advance of the following standardized nomination times

Timely	11 30 a m
Evening	6 00 p m
Intra-day 1	10 00 a.m
Intra-day 2	5 00 p.m

The Timely and Evening nominations are prior to the start of a Gas Day The Timely nomination is mandatory The remaining three nomination times are optional. Intra-day nomination changes are subject to Elapsed Prorated Scheduled Quantity (EPSQ) rules EPSQ is defined as the portion of the scheduled gas quantity that would have flowed, up to the effective time of gas flow of the intra-day nomination. EPSQ rules divide a daily nomination into 24 hourly increments. Intra-day 1 nominations may not be less than ~~eight~~sixteen hours of prorated flow (effective time of 5 00 p m) Intra-day 2 nominations may not be less than 12 hours of prorated flow (effective time of 9 00 p m) Company reserves the right to refuse nominations to maintain balance of its system C

IMBALANCE PROVISIONS

Daily Variance Penalty When customer's actual daily receipts from Company are more than ± 5% of customer's daily nomination, customer is subject to imbalance penalties The net daily variance will be determined by comparing customer's actual metered use with the volume nominated The net daily variance will not be subject to an imbalance penalty if customer use does not deviate more than ± 5% If customer use deviates more than ± 5%, the net daily variance will be whatever amount is in excess of the ± 5% deviation The net daily variance will be assessed a penalty of $0.05 per Therm However, in the event of an operational flow order (OFO), system operation limitation (SOL) or critical day, customer's daily receipts shall be limited to customer's daily nomination

Monthly Cashout Mechanism The customer's monthly imbalance is the difference between (1) the sum of customer's daily nominations for the month and (2) the customer's actual metered use, plus the lost and unaccounted for factor Monthly imbalances will not be carried forward to the next calendar month N

(Continued on Sheet No 5-13 3)

FIRM TRANSPORTATION SERVICE (Continued)
RATE CODE 415

Section No. 5
1st Revised Sheet No 13.3

MONTHLY UNDERTAKE / OVERTAKE ~~PURCHASE PAYMENT~~CHARGE ~~NC~~

Customers ~~who use~~using less gas than the volume customer nominated and delivered to the Company system agrees to sell the undertake ~~gas~~ to Company ~~at~~ at the applicable undertake rate. Customer using more gas than the volume customer nominated and delivered to the NSP system agrees to purchase the overtake at the applicable overtake rate. ~~Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.~~ The Monthly Index Price (MIP) shall equal the arithmetic average of all "Weekly Weighted Average Price" values published by the Gas Daily during the month for gas delivered to Northern Natural Gas Pipeline's Demarcation point. ITC and FTC shall equal the applicable pipeline Interruptible Transportation Commodity or Firm Transportation Commodity rates, respectively.

IMBALANCE LEVEL	OVERTAKE CHARGE	UNDERTAKE CHARGE
0% - 3%	MIP * 1.00 + ITC	MIP * 1.00 + FTC
>3% - 5%	MIP * 1.02 + ITC	MIP * 0.98 + FTC
>5% - 10%	MIP * 1.10 + ITC	MIP * 0.90 + FTC
>10% - 15%	MIP * 1.20 + ITC	MIP * 0.80 + FTC
>15% - 20%	MIP * 1.30 + ITC	MIP * 0.70 + FTC
>20%	MIP * 1.40 + ITC	MIP * 0.60 + FTC

~~Monthly Imbalance %~~	~~Undertake Purchase Rate~~
~~100% to 98%~~	~~Index + Applicable Pipeline Firm Transportation Commodity rate(s)~~
~~98% to 90%~~	~~[Index + Applicable Pipeline Firm Transportation Commodity rate(s)] x 0 75~~
~~Less than 90%~~	~~[Index + Applicable Pipeline Firm Transportation Commodity rate(s)] x 0 50~~

~~The index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation).~~ The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to. GRTI surcharge, ACA surcharge, fuel costs and firm or interruptible transportation commodity charge All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise However, Company will treat similarly situated customers on a non-discriminatory basis C

~~N~~

(Continued on Sheet No 5-13 4)

FIRM TRANSPORTATION SERVICE (Continued)
RATE CODE 415

Section No. 5
1st Revised Sheet No 13 3

ND

~~**OVERTAKE CHARGE**~~

~~Customers who use more gas than the volume customer nominated and delivered to the Company system agree to purchase the overtake gas from Company. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.~~

~~Monthly Imbalance %~~	~~Overtake Rate~~
~~100% to 102%~~	~~Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)~~
~~102% to 110%~~	~~[Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)] x 1.25~~
~~Greater than 110%~~	~~[Index + Applicable Pipeline Interruptible Transportation Commodity rate(s)] x 1.50~~

~~The index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). The applicable pipeline commodity rate consists of all pipeline charges including, but not limited to, GRI surcharge, ACA surcharge, fuel costs and interruptible transportation commodity charge. All conditions of the monthly cashout mechanism apply unless customer and Company agree otherwise. However, Company will treat similarly situated customers on a non-discriminatory basis.~~

D

LATE PAYMENT CHARGE
A 1% late payment charge will be added to the unpaid balance on due date

SURCHARGE
Bills are subject to the applicable surcharge provided for in the Surcharge Rider

N

(Continued on Sheet No 5-13 4)

STANDBY SERVICE RIDER

Section No 5
2nd Revised Sheet No 24

CANCELED

~~**AVAILABILITY**~~

~~Available to any Firm Transportation Service customer who desires to reserve a specified number of days of firm gas supply in a Standby Service Agreement with Company during the term of agreement.~~

~~**CHARACTER OF SERVICE**~~

~~Company in its sole discretion may decline to enter into Standby Service Agreements or limit the days of availability and shall consider the Company's estimate of its distribution capacity and stored gas availability to provide Standby Service.~~

~~**CURTAILMENT**~~ T

~~If the Company's system operations require curtailment of firm service, service hereunder will be curtailed before all other firm service, and customer will be credited a portion of the Availability Charge based on the days of curtailed firm service and that contracted for.~~

~~**THERM ADJUSTMENT**~~

~~Customer's consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit.~~

~~**SUPERCOMPRESSIBILITY ADJUSTMENT**~~

~~For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility.~~

~~**RATE**~~

~~Availability Charge - As specified in the Standby Service Agreement between customer and Company.~~

~~Distribution Charge per Therm~~	~~$0.11280~~	C
~~Cost of Gas Charge per Therm~~	~~see below~~	N

T

~~**DETERMINATION OF COST OF GAS**~~ C

~~The Cost of Gas Charge per therm shall be based on the current replacement cost of propane. The Cost of gas shall be equal to $0.0110 per therm for each $0.0100 of the cost per gallon of replacement propane.~~ C

(Continued on Sheet No 5-25)

STANDBY SERVICE RIDER (Continued)

Section No 5
Original Sheet No 25

CANCELED

N

~~**ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION**~~

~~If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1 00 per Therm, or (ii) an amount equal to any payment Company is required to make to its transporting pipeline as a result of such failure to curtail, interrupt, or restrict service Such payments, however shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail, interrupt, or restrict the use thereof when requested by Company to do so~~

~~**SURCHARGE**~~

~~Bills are subject to the applicable surcharge provided for in the Surcharge Rider~~

~~**LATE PAYMENT CHARGE**~~

~~A 1% late payment charge will be added to the unpaid balance on due date~~

~~**TERM OF AGREEMENT**~~

~~Standby Service Agreement shall be for a period up to 12 months terminating June 30~~

N

LIMITED FIRM SERVICE RIDER

Section No 5
1st Revised Sheet No 26

AVAILABILITY

This rate is aAvailable to any Interruptible or Interruptible Transportation Service customer who, when subject to interruption or curtailment, desires to supplement its service by reserving a specified number of days of firm gas service in a Limited Firm Service Agreement with Company Limited Firm Service will be restricted to 10 days for Small Volume customers and 15 days for Large Volume customers during the term of agreement I

CHARACTER OF SERVICE

Company in its sole discretion may decline to enter into Limited Firm Service Agreements or limit the days of availability and shall consider the Company's estimate of its distribution capacity and stored gas availability to provide Limited Firm Service.

CURTAILMENT

If the Company's system operations require curtailment of firm service, service hereunder will be curtailed before all other firm service, and customer will be credited a portion of the Availability Charge based on the days of curtailed firm service and that contracted for ~~I~~

THERM ADJUSTMENT

Customer's Therm usage shall equal their Ccf consumption ~~in Ccf will be~~ adjusted to reflect 1,000 Btu per cubic foot, a base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit. I I

SUPERCOMPRESSIBILITY ADJUSTMENT

For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

COST OF PROPANE GAS RATE

Availability Charge As specified in the Limited Firm Service Agreement between customer and Company

~~Distribution Charge per Therm~~	~~$0 11280~~	~~C~~D
~~Cost of Gas Charge per Therm~~	~~see below~~	~~N~~D
Operational Cost per Therm	$0.13468	C
Cost of Propane Gas per Therm	$0.71415	C
Total Cost per Therm	$0.84883	C

(Continued on Sheet No 5-27)

LIMITED FIRM SERVICE RIDER

Section No 5
1st Revised Sheet No 26

DETERMINATION OF COST OF GAS

~~The Cost of Gas Charge per Therm shall be based on the current replacement cost of propane The Cost of gas shall be equal to $ 0110 per therm for each $ 0100 of the cost per gallon of replacement propane~~ If the Company's average inventory propane cost for this rider differs from $0.64923 per gallon, the Cost of Propane Gas per Therm shall be adjusted by 1.1 times the difference. C C

DISTRIBUTION CHARGE N

All usage shall be assessed the distribution charge per Therm from Customer's applicable interruptible rate. N

(Continued on Sheet No 5-27)

PARTIAL DECOUPLING RIDER

Section No 5
Original Sheet No 28

APPLICABILITY N

This rider applies to all Residential customers.

ADJUSTMENT TO RATE SCHEDULE

Effective. September 1, 2006
The adjustment for Residential customers is $0.00000 per Therm.

DEFINITIONS

For the purposes of this tariff, the following definitions apply.

Monthly Weather Normalized Use Per Customer = weather-normalized actual sales for the Residential class during the month divided by the actual number of Residential customers during the same month. The weather-normalized actual sales for the Residential class will be calculated using the same approach to weather normalization established in the Company's last general rate case (Docket No. PU-400-04-578).

Monthly Test Year Use Per Customer = Residential use per customer for the month approved or used by the Commission to derive Residential rates in the Company's last general rate case (Docket No. PU-400-04-578).

Residential Distribution Rate Per Therm = Residential Distribution Charge per Therm effective during the month under the provisions of the Residential Firm Service tariff.

Monthly Test Year Customers = number of Residential customers for the month approved or used by the Commission to derive Residential rates in the Company's last general rate case (Docket No. PU-400-04-578).

Annual Carrying Charge = before-tax weighted cost of capital approved by the Commission in the Company's last general rate case X the balance in the Monthly Distribution Margin Differentials subaccount as of June 30.

Annual Rate Adjustment Per Therm = Annual Distribution Margin Differential Adjustment / projected Residential use in therms from September 1 of the year in which the Annual Distribution Margin Differential Adjustment was calculated through August 31 of the following year.

PARTIAL DECOUPLING DEFERRAL ACCOUNT

1. Each month for the Residential class the Company will calculate the difference between the Monthly Weather Normalized Use Per Customer and the Monthly Test Year Use Per Customer. The resulting difference shall be multiplied by the Residential Distribution Charge Per Therm effective during that month and by the Monthly Test Year Customers. The resulting product will be the Monthly Distribution Margin Differential. N

PARTIAL DECOUPLING RIDER (Continued)

Section No 5
Original Sheet No 29

PARTIAL DECOUPLING DEFERRAL ACCOUNT (Continued)

N

2. The Company will defer and amortize the Monthly Distribution Margin Differentials in a subaccount of Account 186. Each year on June 30 an Annual Carrying Charge will be added to the balance in this subaccount to yield the Annual Distribution Margin Differential Adjustment.

Partial Decoupling Rate Adjustment

1. Each year during the term of this rider the Company will calculate an Annual Rate Adjustment Per Therm. This adjustment will be applied to Residential bills from September 1 through August 31 and will be implemented through a revised Residential Energy Charge through a revision to Rate Schedule 5-1. The revised Residential Energy Charge will equal the base Energy Charge approved by the Commission in Docket No. PU-400-04-xxx plus the applicable Partial Decoupling Rate Adjustment.

2. The Company shall file by September 1 of each year its determination of the Annual Rate Adjustment Per Therm with all supporting information used to determine this rate adjustment. This filing shall include the revised Residential and Partial Decoupling Rate Adjustment tariffs needed to implement the applicable rates.

3. Any under- or over-recovery of the Annual Distribution Margin Differential Adjustment will be included as a deferral in the Monthly Distribution Margin Differentials subaccount and reflected in the calculation of the following year's Annual Rate Adjustment Per Therm.

SUNSET DATE

This mechanism shall allow for three annual partial decoupling rate adjustments. Customers' bill shall be adjusted through the August 2009 billing month. This tariff terminates September 1, 2009.

N

GENERAL RULES AND REGULATIONS (Continued)

Section No 6
1st Revised Sheet No 11

3.6 BILL DATE DUE

Bills are due and payable upon presentation For purposes of applying the late payment charge, the date due shown on the customer's bill shall be

Class	Date Due
Interruptible	Minimum of 10 working days after bill mailing date
All Other Classes	Next scheduled billing date minus four working days

3.7 ESTIMATED BILLS

An estimated bill will be rendered if it is impractical for the Company to read the meter or if customer fails to supply a meter reading form in time for the billing operation, or in cases of emergency An adjustment, if any, will be made in the bill based on the next meter reading

3.8 BILLING ADJUSTMENTS

In the event of a meter or billing error, as defined by the Public Service Commission's rules, the Company shall recalculate the bills for service during the period of the error and make adjustment of bills in accordance with the rules prescribed by the Commission If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10.00

3.9 RETURNED CHECK CHARGE

There shall be a charge of $25 00 for any check or draft submitted to the Company for payment ~~which~~that is dishonored or returned by the financial institution on which it is drawn I

3.10 ACCOUNT HISTORY CHARGE

There shall be a charge of $0.50 per account to the authorized requesting party for providing account history when such request involves 10 or more accounts, regardless of the type of account or number of meters An authorized requesting party may be the customer, a person authorized by the customer, or a person authorized by law to receive the requested information.

GENERAL RULES AND REGULATIONS (Continued)

Section No 6
1st Revised Sheet No 18

5.2 MAIN EXTENSIONS

The Company will extend, enlarge, or change its gas mains or other facilities for supplying gas service when the anticipated revenue from the sale of additional service to result therefrom is such as to justify the expenditure When the expenditure is not so justified, the extension, enlargement, or change of facilities will be made only if the customer, at the Company's option

A Pays in advance to the Company in cash for the additional installation costs for excess footage as required by the ~~Excess Footage Charge~~ Company's current footage costs or by promissory note acceptable to the Company, the portion of the capital expenditure not justified by the anticipated annual revenue with provision for refund of all or part of such payment, C

B Agrees to pay a special monthly charge,

C. Agrees to pay annually a specified minimum charge, or

D Agrees to a combination of the above methods.

In addition, a non-refundable payment in advance must be made covering the specified additional cost of any unusual construction.

For each additional customer served directly from the main extension within five years from the date of its completion, the person who made advance payment will receive refunds based on the revenue to be received from the additional customers served from the extension and the costs required to serve such customers The total of such refunds will in no event exceed the total advance payment No refunds will be made for additional customers served by additional main extensions connected at any point to the first customer's original extension.

For trailer parks, the Company will only extend its gas main to a delivery point at a permanent structure which houses facilities such as offices or laundry facilities It shall be the trailer park owner's responsibility to extend the distribution system to individual trailer sites

D

~~Excess Footage Charge~~

~~Main Extensions~~	~~2 Inch or Under Pipe~~	~~$2 75 per foot~~
	~~3 Inch Pipe~~	~~$3 80 per foot~~
	~~4 Inch Pipe~~	~~$5 25 per foot~~
	~~Over 4 Inch Pipe~~	~~Determined Individually~~

D

(Continued on Sheet No 6-19)

5.3 WINTER CONSTRUCTION

When the service or main is installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30 or because the customer's property, or the streets leading thereto, are not ready to receive the service pipe or gas main by such date, such work will be subject to a winter construction charge when winter conditions of ground frost and/or snow exist, for the entire length of underground service or gas main installed. Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install gas main or gas service pipe during the winter season The charges immediately below apply to frost depths of 18" or less. At greater frost depths, the Company will individually determine the job cost. The Company reserves the right to charge for any unusual winter construction expenses. All winter construction charges are non-refundable and are in addition to any normal construction charges C

Winter Construction Charge		
~~Main Extensions~~Excavation	~~$3 00 per foot~~	$400 per excavating unit
Main & Service Extensions	4 Inch or Under Pipe	~~$100 00 plus~~ $3.00 per foot
	Over 4 Inch Pipe	Determined Individually

C

5.4 LIMITATIONS ON THE AVAILABILITY OF GAS

New and existing customers requiring service for new or increased firm or interruptible gas loads must make an application for such service. The Company shall apply the applicable limitations set forth in this section in determining whether to approve an application When supplies of gas and distribution capacity are adequate, Company will authorize connection of qualifying customers in the order that their application is received When an applicant is one for which a main extension is required, the application will be held until the main extension is approved, at which time it shall be processed the same as an on-main customer

A New and Existing Firm Customers

1 New customers will be added in accordance with Section 5, EXTENSION RULES, of the General Rules and Regulations.

2 Existing loads, except as noted below, may be increased and new loads added only with the approval of the Company based upon the adequacy of gas supplies and gas distribution capacity

3. Increases in existing loads for non-heating requirements not in excess of 0 5 Therm per hour do not require Company approval in accordance with Section 1.1, APPLICATION FOR SERVICE, of the General Rules and Regulations.

(Continued on Sheet No 6-20)

5.5 SERVICE CONNECTIONS (Continued)

In addition, the Company will, at its own expense for all customers, furnish and install piping for a distance not to exceed five feet for

A Indoor Metering
From the service to the meter header or meter yoke.

B Outdoor Metering
From the end of the horizontal service pipe to the outside of the customer's building wall

If this distance exceeds five feet in length, the Company will extend the piping if the customer will share the cost based on the Company's current footage costs ~~The following schedule of charges will be applied to service extensions exceeding the extension limits~~ C C

~~Excess Footage Charge~~ D

~~Service Extensions~~	~~1-1/4 Inch or Under Pipe~~	~~$1.50 per foot~~
	~~2 Inch Pipe~~	~~$2.75 per foot~~
	~~3 Inch Pipe~~	~~$3.80 per foot~~
	~~4 Inch Pipe~~	~~$5.25 per foot~~
	~~Over 4 Inch Pipe~~	~~Determined Individually~~ D

5.6 TEMPORARY SERVICE

The following special requirement is prescribed to govern temporary service.

A customer taking temporary service (less than five years) will pay the rate applicable to the class of service rendered and will pay in advance the Company's specified cost, figured on a time and material basis, of the installation and removal of the facilities, including the meter required to furnish the desired service, less the salvage value of such facilities

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Summary of Present and Proposed Rates

Firm Sales Service	Present Rates	Proposed Rates
Residential		
Basic Service Charge	$5.50 / Month	$8.50 / Month [$14 00/mo.]*
Distribution Charge	$0.12480 /Therm	$0.12388 /Therm [$0 04833/Th]*
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0 68199 /Therm	$0.68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Commercial and Industrial - Firm		
Basic Service Charge	$14.00 /Month	$20.00 /Month
Distribution Charge	$0.11280 /Therm	$0.10120 /Therm
Cost of Gas		
Summer	$0.62934 /Therm	$0.62934 /Therm
Winter	$0.68199 /Therm	$0.68199 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Small Interruptible Service		
Basic Service Charge	$75.00 /Month	$75.00 /Month
Distribution Charge	$0.07310 /Therm	$0.07740 /Therm
Cost of Gas	$0.54166 /Therm	$0.54166 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm
Large Interruptible Service		
Basic Service Charge	$275.00 /Month	$275.00 /Month
Distribution Charge	$0.04390 /Therm	$0.04632 /Therm
Cost of Gas	$0.54166 /Therm	$0.54166 /Therm
MGP amortization	$0.00368 /Therm	$0.00368 /Therm

* Alternative charges, without partial decoupling mechanism

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Proposed Rates

RESIDENTIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Proposed	Amount	Percent
0	$5.50	$8 50	$3 00	54 5%
10	$13 60	$16 60	$2 99	22 0%
20	$21 71	$24 69	$2.98	13 7%
30	$29 81	$32.79	$2.97	10 0%
40	$37 92	$40 88	$2 96	7 8%
50	$46 02	$48 98	$2 95	6 4%
75	$66 29	$69.22	$2 93	4 4%
100	$86 55	$89 45	$2 91	3.4%
200	$167 59	$170 41	$2 82	1.7%
300	$248 64	$251 36	$2 72	1.1%
500	$410 73	$413 27	$2 54	0 6%

COMMERCIAL & INDUSTRIAL FIRM SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Proposed	Amount	Percent
0	$14 00	$20.00	$6.00	42 9%
50	$53 92	$59 34	$5 42	10 1%
100	$93 85	$98 69	$4 84	5.2%
250	$213 62	$216 72	$3 10	1.5%
500	$413 23	$413 43	$0.20	0.0%
750	$612 85	$610 15	($2 70)	-0 4%
1000	$812 47	$806 87	($5 60)	-0 7%
3000	$2,409 40	$2,380 60	($28 80)	-1 2%
5000	$4,006 34	$3,954 34	($52.00)	-1.3%
7500	$6,002 51	$5,921 51	($81.00)	-1 3%
10000	$7,998 68	$7,888 68	($110 00)	-1 4%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Monthly Winter Bills Using Present and Proposed Rates

SMALL VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Proposed	Amount	Percent
1,000	$693 44	$697 74	$4 30	0 6%
3,000	$1,930 31	$1,943.21	$12 90	0 7%
5,000	$3,167 19	$3,188.69	$21 50	0 7%
7,500	$4,713 28	$4,745 53	$32 25	0 7%
10,000	$6,259 38	$6,302 38	$43 00	0 7%

LARGE VOLUME INTERRUPTIBLE SERVICE

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Proposed	Amount	Percent
1,000	$864 24	$866 66	$2 42	0 3%
3,000	$2,042 71	$2,049 97	$7 26	0.4%
5,000	$3,221 19	$3,233 29	$12 10	0 4%
7,500	$4,694 28	$4,712 43	$18 15	0 4%
10,000	$6,167 38	$6,191.58	$24 20	0.4%

RESIDENTIAL FIRM SERVICE (alternate rate)

Monthly Use	BILLING		INCREASE	
(Therms)	Present	Proposed	Amount	Percent
0	$5 50	$14 00	$8 50	154 5%
10	$13 60	$21 34	$7 74	56 9%
20	$21 71	$28 68	$6 97	32.1%
30	$29 81	$36 02	$6 21	20 8%
40	$37 92	$43 36	$5 44	14 3%
50	$46 02	$50 70	$4 68	10 2%
75	$66 29	$69 05	$2 76	4 2%
100	$86 55	$87 40	$0 85	1 0%
200	$167 59	$160 80	($6 79)	-4 1%
300	$248 64	$234 20	($14 44)	-5 8%
500	$410 73	$381 00	($29 73)	-7 2%

orthern States Power Company d/b/a Xcel Energy
as Utility - State of North Dakota
)04 Test year
ummary of Customers, Sales and Present and Proposed Revenues

	Rate Code	Avg Cust.	Dkt Sales	Revenue Present	Revenue Proposed	Increase Amount	Increase %
Firm Service							
Residential	401	34,553	3,018,662	$26,361,011	$27,577,162	$1,216,151	4.6%
Commercial and Industrial	410	6,141	3,800,045	$30,884,941	$30,886,270	$1,329	0 0%
Total Firm Service		**40,694**	**6,818,707**	**$57,245,953**	**$58,463,433**	**$1,217,480**	**2.1%**
Interruptible Service							
Small Volume	404	110	616,604	$3,912,461	$3,938,974	$26,513	0 7%
Lg Vol/Neg Transp	405	23	2,353,612	$7,682,678	$7,713,308	$30,629	0 4%
Total Interruptible Service		**133**	**2,970,216**	**$11,595,140**	**$11,652,282**	**$57,142**	**0.5%**
Total Gas Sales		**40,827**	**9,788,923**	**$68,841,092**	**$70,115,715**	**$1,274,622**	**1.9%**
Other Gas Revenues							
Connection Charge				$45,000	$45,000	$0	0 0%
Late Payment Charge				$131,000	$133,220	$2,220	1 7%
Gas Agreement				$26,000	$26,000	$0	0 0%
NSF Check Charge				$1,694	$5,084	$3,390	200.1%
Miscellaneous				$67,000	$67,000	$0	0.0%
Gross Receipts Tax				$979,000	$979,000	$0	0 0%
Other sales				$1,475,000	$1,475,000	$0	0 0%
Meter Calibration Adjustment				$41,000	$41,000	$0	0 0%
Total Other Gas Revenues				**$2,765,694**	**$2,771,304**	**$5,610**	**0.2%**
Total Sales and Other Gas Revenues				**$71,606,786**	**$72,887,018**	**$1,280,232**	**1.8%**

Residential Service - without Space Heating

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	16,037		$ 5 50	$ 88,204	$ 8 50	$ 136,315	$ 48,111	
Distribution Charge		361,520	$ 0.12480	$ 45,118	$ 0 12388	$ 44,785	$ (333)	
MGP Recovery			$ 0 00368	$ 1,330	$ 0 00368	$ 1,330	$ -	
Gas Supply Charge								
Summer (Apr-Oct)		72,730	$ 0 62934	$ 45,772	$ 0 62934	$ 45,772		
Winter (Nov-Mar)		288,790	$ 0 68199	$ 196,952	$ 0 68199	$ 196,952		
Total (all therms)		361,520		$ 242,724		$ 242,724	$ -	
Average Customers	1,336							
			Total	$ 377,376		$ 425,154	47,778	12 7%

Residential Service - with Space Heating

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	398,604		$ 5 50	$ 2,192,322	$ 8 50	$ 3,388,134	$ 1,195,812	
Distribution Charge		29,825,100	$ 0 12480	$ 3,722,172	$ 0 12388	$ 3,694,733	$ (27,439)	
MGP Recovery			$ 0 00368	$ 109,686	$ 0.00368	$ 109,686	$ -	
Gas Supply Charge								
Summer (Apr-Oct)		7,235,790	$ 0 62934	$ 4,553,772	$ 0 62934	$ 4,553,772		
Winter (Nov-Mar)		22,589 310	$ 0 68199	$ 15,405,684	$ 0 68199	$ 15,405,684		
Total (all therms)		29,825,100		$ 19,959,456		$ 19,959,456	$ -	
Average Customers	33,217							
			Total	$ 25,983,636		$ 27,152,009	$ 1,168,373	4.5%

Commercial and Industrial Service without Space Heating

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	4,023		$14 00	$ 56,322	$20 00	$ 80,460	$ 24,138	
Distribution Charge		1,652,070	$ 0 11280	$ 186,353	$ 0 10120	$ 167,189	$ (19,164)	
MGP Recovery			$ 0 00368	$ 6,076	$ 0 00368	$ 6,076	$ -	
Gas Supply Charge								
Summer (Apr-Oct)		414,890	$ 0 62934	$ 261,107	$ 0 62934	$ 261,107		
Winter (Nov-Mar)		1,237,180	$ 0 68199	$ 843,744	$ 0 68199	$ 843,744		
Total (all therms)		1,652,070		$ 1,104,851		$ 1,104,851	$ -	
Average Customers	335							
			Total	$ 1,353,602		$ 1,358,576	$ 4,974	0 4%

Commercial and Industrial Service with Space Heating

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	69,666		$14 00	$ 975,324	$20 00	$ 1,393,320	$ 417,996	
Distribution Charge		36,348,380	$ 0 11280	$ 4,100,097	$ 0 10120	$ 3,678,456	$ (421,641)	
MGP Recovery			$ 0 00368	$ 133,676	$ 0 00368	$ 133,676	$ -	
Gas Supply Charge								
Summer (Apr-Oct)		8,869,680	$ 0 62934	$ 5,582,044	$ 0 62934	$ 5,582,044		
Winter (Nov-Mar)		27,478,700	$ 0 68199	$ 18,740,199	$ 0 68199	$ 18,740,199		
Total (all therms)		36,348,380		$ 24,322,243		$ 24,322,243	$ -	
Average Customers	5,806							
			Total	$ 29,531,340		$ 29,527,695	$ (3,645)	0 0%

Small Interruptible Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	1,322		$ 75 00	$ 99,150	$ 75 00	$ 99,150	$ -	
Distribution Charge		6,166,040	$ 0 07310	$ 450,738	$ 0 07740	$ 477,251	$ 26,513	
MGP Recovery			$ 0 00368	$ 22,676	$ 0 00368	$ 22,676	$ -	
Gas Supply Charge		6,166,040	$ 0 54166	$ 3,339,897	$ 0 54166	$ 3,339,897	$ -	
Average Customers	110							
			Total	$ 3,912,461		$ 3,938,974	$ 26,513	0 7%

Large Interruptible Service/Negotiated Transportation Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	275		$ 275 00	$ 75,925	$ 275 00	$ 75,925	$ -	
Distribution Charge		23,536,120	$ 0 04390	$ 1,033,236	$ 0 04632	$ 1,090,193	$ 56,957	
Discount		10,879,170	$ 0 03390	$ (368,804)	$ 0 03632	$ (395,131)	$ (26,328)	
MGP Recovery		23,536,120	$ 0 00368	$ 86,557	$ 0 00368	$ 86,557	$ -	
Gas Supply Charge		12,656,950	$ 0 54166	$ 6,855,764	$ 0 54166	$ 6,855,764	$ -	
Average Customers	23							
			Total	$ 7,682,678		$ 7,713,308	$ 30,629	0 4%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Comparison of Proposed Rate Design and Class Cost of Service Study Results
(000's)

		(1)	(2)	(3)	(4)	(5)
Customer Class		**Present Revenues**	**Revenue Deficiency Indicated by CCOSS**	**Total Effect Of Proposed Rates**	**Difference Between CCOSS Revenue Deficiency and Proposed Rates**
Residential	$ increase	$26,361	$3,009	$1,216	$1,793
	% increase		11.4%	4.6%	6 8%
Commercial	$ increase	$30,885	($1,119)	$1	($1,120)
	% increase		-3 6%	0 0%	-3.6%
Interruptible Service	$ increase	$3,912	($291)	$27	($318)
(Small Volume)	% increase		-7 4%	0.7%	-8 1%
Interruptible Service	$ increase	$7,683	($319)	$31	($350)
(Large Volume)	% increase		-4 2%	0 4%	-4 6%
Other Revenues	$ increase	$2,766		$6	
	% increase				
Total	$ increase	$71,607	$1,280	$1,280	($0)
	% increase		1 8%	1 8%	0 0%

Rate Design - Class Impact by Rate Component

		(1)	(2)	(3)	(4)
			Overall Impacts of Proposed Rates		
Customer Class		**Present Revenues**	**Basic Service Charges**	**Distribution Charges**	**Total Effect of All Changes**
Residential	$ increase	$26,361	$1,244	($28)	$1,216
	% increase		4 7%	-0.1%	4.6%
Commercial	$ increase	$30,885	$442	($441)	$1
	% increase		1.4%	-1 4%	0.0%
Small Interruptible	$ increase	$3,912	$0	$27	$27
	% increase		0.0%	0.7%	0 7%
Large Interruptible	$ increase	$7,683	$0	$31	$31
	% increase		0.0%	0 4%	0.4%
Total	$ increase	$68,841	$1,686	($411)	$1,275
	% increase		2.4%	-0 6%	1.9%

ROE = 7.87%
Deficiency = $1,280
% Increase = 1.86%
Required ROE = 11.50%

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Test Year

Summary Reports

October 26, 2004

Average Rate Base	$42,398
Total Available for Return	$3,224
Overall Rate of Return (Line 2 / Line 1)	7 60%
Required Rate of Return	9 43%
Operating Income Requirement (Line 1 x Line 4)	$3,998
Income Deficiency (Line 5 - Line 2)	$774
Gross Revenue Conversion Factor	1 654260
Revenue Deficiency (Line 6 x Line 7)	$1,280
Retail Related Revenue Under Present Rates	$68,841
Percentage Increase (Line 8 / Line 9)	1 86%

Printed: 10/26/2004 13 53

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Test Year
(Dollars in Thousands)

Rate Base Summary

		Total Company Gas			North Dakota Retail Gas			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	795,836	847,026	821,431	72,704	77,377	75,041	723,132	769,649	746,390
2	Depreciation Reserve	(340,180)	(369,926)	(355,053)	(31,329)	(34,034)	(32,682)	(308,851)	(335,892)	(322,371)
3	Net Utility Plant	455,656	477,100	466,378	41,375	43,343	42,359	414,281	433,757	424,019
4	C.W I P	659	834	747	118	84	101	541	750	646
5	Accumulated Deferred Taxes	(62,585)	(68,608)	(65,597)	(5,652)	(6,234)	(5,943)	(56,933)	(62,374)	(59,654)
	Other Rate Base									
6	Cash Working Capital	(8,675)	(8,675)	(8,675)	(549)	(549)	(549)	(8,126)	(8,126)	(8,126)
7	Materials & Supplies	2,071	2,071	2,071	188	188	188	1,883	1,883	1,883
8	Gas In Storage	34,722	34,722	34,722	3,834	3,834	3,834	30,888	30,888	30,888
9	Non-Plant Assets & Liab	(7,163)	(6,676)	(6,920)	(593)	(556)	(574)	(6,570)	(6,121)	(6,346)
10	Prepaids & Other	13,243	12,883	13,063	3,162	2,802	2,982	10,081	10,081	10,081
11	**Total Rate Base**	**427,928**	**443,651**	**435,789**	**41,883**	**42,912**	**42,398**	**386,046**	**400,739**	**393,391**

Income Statement Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Operating Revenues			
1	Retail	659,264	68,678	590,586
2	Net Margin Weather Adjustment	0	0	0
3	Interdepartmental & Transportation	8,702	163	8,539
4	Other Operating	18,273	1,787	16,486
5	Gross Earnings Tax	7,536	979	6,557
6	**Total Operating Revenues**	**693,776**	**71,607**	**622,169**
	Expenses			
	Operating Expenses:			
7	Purchased Gas	534,510	57,267	477,243
8	Production	3,678	724	2,953
9	Transmission	869	96	773
10	Distribution	22,917	1,664	21,252
11	Customer Accounting	11,054	1,142	9,913
12	Customer Service & Information	5,961	80	5,881
13	Administrative & General	16,852	1,458	15,394
14	Amortizations	252	20	232
15	Sales, Econ Dvlp & Other	239	131	108
16	Total Operating Expenses	596,331	62,582	533,750
17	Depreciation	29,665	2,698	26,967
	Taxes:			
18	Property	13,234	1,003	12,232
19	Gross Earnings	7,536	979	6,557
20	Deferred Income Tax & ITC	5,691	551	5,140
21	State & Federal Income (see Page 3)	4,886	408	4,478
22	Payroll & Other	2,160	163	1,997
23	Total Taxes	33,507	3,104	30,404
24	**Total Expenses**	**659,503**	**68,383**	**591,120**
25	AFUDC	0	0	0
26	**Total Operating Income**	**34,273**	**3,224**	**31,049**

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Test Year
(Dollars in Thousands)

Income Tax Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Income Before Taxes			
1	Total Operating Revenues	693,776	71,607	622,169
2	less Total Operating Expenses	(596,331)	(62,582)	(533,750)
3	Book Depreciation	(29,665)	(2,698)	(26,967)
4	Taxes (Other Than Current Income)	(28,621)	(2,696)	(25,926)
5	**Total Before Tax Book Income**	**39,158**	**3,632**	**35,526**
	Tax Additions			
6	Book Depreciation	29,665	2,698	26,967
9	Book Depreciation Cleared To Operating	858	78	780
10	Deferred Income Taxes & ITC	5,691	551	5,140
11	Book Amortizations	20	20	0
12	Connection Fees	888	81	807
13	Avoided Tax Interest	1,157	106	1,051
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	38	3	35
16	TBT Net Expense	(3)	0	(3)
17	**Total Tax Additions**	**38,314**	**3,537**	**34,777**
	Tax Deductions			
18	Tax Depreciation & Removal Expense	50,107	4,664	45,443
19	Debt Interest Expense	15,915	1,548	14,366
20	Other Tax/Book Timing Differences	(520)	(75)	(445)
21	Net Preferred Stock Deduction	0	0	0
22	**Total Tax Deductions**	**65,502**	**6,137**	**59,364**
23	**State Taxable Income**	**11,971**	**1,032**	**10,939**
24	State Income Tax Rate	8 95%	7 00%	N/A
25	**Total State Income Taxes**	**1,071**	**72**	**999**
26	**Federal Taxable Income**	**10,900**	**959**	**9,941**
27	Federal Income Tax Rate	35 00%	35 00%	35 00%
28	**Total Federal Income Taxes**	**3,815**	**336**	**3,479**
29	**Total Federal & State Income Taxes**	4,886	408	4,478

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Test Year

Revenue Requirement & Return Summary

(Dollars in Thousands)

	2004 Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	7 3300%	48 6530%	3 5663%
2	Short Term Debt	7 7400%	1 1070%	0 0857%
3	Preferred Stock	0 0000%	0 0000%	0 0000%
4	Common Equity	11 5000%	50 2400%	5 7776%
5	**Required Rate of Return**			**9.4295%**

	Composite Income Tax Rates		
	State of North Dakota Tax rate		7 00%
	Federal Statutory Tax rate	35 00%	
	Federal Effective Tax Rate (1-State Rate * Fed Rate)		32 55%
	Total North Dakota Composite Tax Rate		**39.55%**
	Total Corporate Composite Tax Rate		**40.81%**

		Total Company Gas	North Dakota Retail Gas	All Other
	Rate of Return (ROR)			
6	Total Operating Income	34,273	3,224	31,049
7	Total Average Rate Base	435,789	42,398	393,391
8	**ROR (Operating Income / Rate Base)**	**7.86%**	**7.60%**	**7.89%**
	Return on Equity (ROE)			
9	Total Operating Income	34,273	3,224	31,049
10	Debt Interest (Rate Base * Weighted Debt Cost)	(15,915)	(1,548)	(14,366)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	18,358	1,676	16,682
13	Equity Rate Base (Rate Base * Equity Ratio)	218,940	21,301	197,640
14	**ROE (Earnings for Common / Equity Rate Base)**	**8.38%**	**7.87%**	**8.44%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Retu	41,093	3,998	37,095
16	Operating Income	34,273	3,224	31,049
17	Operating Income Deficiency	6,820	774	6,046
18	Revenue Conversion Factor (1/(1-Composite Tax Rate	1 68960	1 65426	N/A
19	**Revenue Deficiency (Income Deficiency * Conversion I**	**11,523**	**1,280**	**10,243**
	Total Retail Revenue Requirements			
20	Retail Sales Revenues	667,967	68,841	599,126
21	Revenue Deficiency	11,523	1,280	10,243
22	**Total Retail Revenue Requirements**	**679,490**	**70,122**	**609,368**
23	**Percentage Increase (Decrease)**	**1.73%**	**1.86%**	**1.71%**

Rate Base Detail - Cash Working Capital

			Total Company Gas			North Dakota Retail Gas			All Other	
	Expenses									
	Includable Expenses	**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Purchased Gas									
1	Purchases	40 25	534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
2	Subtotal Purchased Gas		534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
	Labor & Related Costs									
3	Regular Payroll	13 79	32,344	446,018		2,721	37,523		29,623	408,496
4	Incentive Compensation	259 51	1,148	297,831		99	25,691		1,049	272,139
5	Pension & Benefits	29 79	4,916	146,447		354	10,546		4,562	135,901
6	Subtotal Labor & Related		38,407	890,296		3,174	73,760		35,233	816,536
7	All Other Operating Expenses	42 34	23,162	980,685		2,121	89,801		21,041	890,884
8	Property Tax	345 46	13,234	4,571,948		1,003	346,422		12,232	4,225,525
9	Employer's Payroll Taxes	19 66	2,160	42,459		163	3,198		1,997	39,261
10	Gross Earnings Tax	71 98	7,536	542,453		979	70,474		6,557	471,979
11	Federal Income Tax	37 00	3,815	141,154		336	12,424		3,479	128,731
12	State Income Tax	37 00	1,071	39,621		72	2,672		999	36,949
13	State Sales Tax Customer Billings	51 86	13,668	708,843		1,111	57,616		12,557	651,227
14	Total Expenses	46 16	637,564	29,431,491	44 72	66,225	2,961,356	46 33	571,339	26,470,135
15	**Net Annual Expense Amount**			80,634			8,113			72,521
	Revenues	**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
16	Computer Billing 100 00%	41 94	659,264	27,649,551		68,678	2,880,359		590,586	24,769,192
19	Interdepartmental	0 00	7,104	0		10	0		7,094	0
20	Transportation	33 21	1,598	53,078		153	5,076		1,445	48,001
21	Late Payment	0 00	2,293	0		131	0		2,162	0
22	Meter Calibration Adjustment	41 94	159	6,668		41	1,720		118	4,949
23	Connect Charge	41 94	456	19,131		45	1,906		411	17,225
24	Return Check Charge	41 94	37	1,550		2	71		35	1,479
27	Gas Agreement	35 21	239	8,428		26	926		213	7,502
29	Balancing Service	35 21	30	1,056		30	1,056		0	0
31	Limited Firm Sales - Res & Vols	35 21	917	32,272		37	1,301		880	30,971
32	Sales to Other - MN LP	35 21	0	0		(0)	(8)		0	8
34	Opportunity Sales	35 21	14,042	494,419		1,475	51,935		12,567	442,484
37	Other Gas Revenue	41 94	100	4,197		0	0		100	4,197
38	Total Revenues	41 20	686,240	28,270,351	41 69	70,628	2,944,342	41 14	615,612	25,326,009
39	Net Annual Amount			77,453			8,067			69,386
40	Expense / Revenue Factor			0 929068739			0 937660736			
41	**Allocated Revenue Amount**			71,959			7,584			
42	**Net Cash Working Capital**	Page 1 - Line 6		(8,675)			(549)			(8,126)

Introduction

With this Notice, Xcel Energy proposes revised tariffs for its North Dakota Gas Rate Book that will increase total natural gas revenues by $1,280,232, or 1.8 percent annually. The increase is proposed to be effective for gas used on and after December 2, 2004, unless the rates are suspended and interim rates are implemented.

The Company also proposes to institute a "partial decoupling" mechanism with final rates to mitigate future revenue erosion due to an established trend of declining use per customer.

Class Cost of Service Study

A. Process

The proposed rates were developed using a Class Cost of Service Study ("CCOSS") to identify the cost of service for each rate class. The CCOSS presented in this case as Schedule 9 is a fully distributed, embedded class cost of service study.

Preparing a CCOSS involves the following steps:

1. Costs are identified by function and separated by jurisdiction. The Jurisdictional Cost of Service Study ("JCOSS") used to separate the Company's system costs is included as Schedule 6.
2. The CCOSS directly assigns costs and revenues to specific customers classes where appropriate (e.g., revenues from sales, cost of gas).
3. The CCOSS classifies the residual costs as customer, demand or commodity-related and allocates them to the various classes of service using appropriate allocators. Examples of such allocators are class customer numbers, class contributions to peak-day requirements, and class annual throughput.
4. The cost of serving each class is compared with the revenues generated under current rates. This analysis yields the cost-based apportionment of the test-year revenue requirement and the unit costs of serving various classes.

A description of the Class Cost of Service Study (CCOSS) submitted as Schedule 9 is provided below:

- Page 1 summarizes some of the results of the CCOSS.
- Page 2, which is also a summary table, shows the functionalized rate base.
- Page 3 summarizes the income statement.
- Pages 4 through 8 show the detailed items and allocations that comprise the functionalized rate base summarized on page 2.
- Pages 9 through 17 show the detailed items and allocations that comprise the income statement summarized on page 3.
- Pages 18 and 19 contain the allocation factors used throughout the study. For quick reference, they are provided as percentages.
- Page 20 contains Cost of Capital information used in the revenue requirement calculations.

B. Process Modifications

The proposed CCOSS is similar to that used in the Company's last general rate case in North Dakota (Case No. PU-400-00-521). The only significant change is that the study filed in this application uses a minimum distribution system to better identify the costs of serving various customer classes. The imputation of a minimum system recognizes that customers with very small usage require a gas distribution system to deliver that service; therefore, the costs of a minimum system should be classified as customer-related costs and allocated accordingly. The remaining main costs can then be treated as either capacity-related or commodity-related costs.

This refinement to the company's CCOSS affects only the treatment of natural gas mains.

C CCOSS Outcomes

The following table provides the required percentage rate increase (or decrease) required to ensure that each class pays 100 percent of its test-year cost of service.

Customer Class	$ Increase	% Increase
Residential	$3,009,000	11.3%
C&I	($1,119,000)	(3.6%)
Small Interruptible	($291,000)	(7.6%)
Large Interruptible	($319,000)	(4.4%)
	$1,280,000	1.9%

Apportionment of Revenue Requirement

The CCOSS was the basis for the proposed revenue apportionment. But the Company also considered other goals, such as the need to charge market-based rates for competitive services and limit rate increases for any class to moderate levels.

The interruptible rates were developed first, based on the market prices of customers' competitive alternatives. The remaining revenue requirement was then apportioned among the firm classes. This proposed apportionment results in rates that more closely recover the costs of serving the various classes. But to soften the impact on residential customers, the Company proposes that this class continue to be subsidized by other classes. No class receives a rate decrease. The end result is that classes pay rates that better reflect their costs of service.

The specific class increases resulting from this approach are summarized below:

Customer Class	$ Increase	% Increase
Residential	$1,216,151	4.6%
C&I	$1,329	0.0%
Small Interruptible	$26,513	0.7%
Large Interruptible	$30,629	0.4%
Retail Sales Revenues	$1,274,622	1.9%
Misc. Revenues	$5,610	0.2%
Total Revenues	$1,280,232	1.8%

Rate Design

A. Process

Most of the Company's current tariffs are structured as two-part rates, consisting of a monthly fixed charge and a volumetric charge applied to a customer's use during the billing period.

While this two-part rate structure adequately achieves most pricing goals, the current proportions of the rate components are inappropriate. Specifically, over half of the fixed costs of providing gas distribution services to residential customers is recovered through volumetric charges.

This pricing methodology causes a number of problems:

1. High-use customers subsidize low-use customers, because high-volume customers contribute disproportionately toward fixed costs. In other words, the recovery of fixed costs through volumetric rates results in intra-class subsidies.
2. Because average residential use per customer is declining, the Company's financial condition is adversely affected. In other words, when fixed costs are recovered through usage-sensitive rates (as they currently are) and usage per customer declines, fixed costs go unrecovered.
3. The recovery of a disproportionately high percentage of fixed costs through volumetric rates leads to some degree of bill instability for customers. This occurs because during periods of high usage (e.g., during cold weather) customers are paying for more fixed costs than they do in other months (e.g., during the summer months).

The Company is proposing two primary remedies in this proceeding. The first is to institute higher monthly fixed charges that more closely reflect the fixed customer-related costs imposed by the various classes. This initiative directly addresses the Company's current pricing problem discussed above. The second remedy is an innovative regulatory mechanism to partially "decouple" the recovery of distribution costs from customer use, over time.

In addition to the benefits of the approach described above, the proposed rates also reflect closely the rate design proposed for Xcel Energy's Minnesota natural gas jurisdiction.

B. Basic Service Charge

The following table compares the proposed Basic Service Charges with their cost-based levels from the CCOSS:

Customer Class	Proposed Monthly Basic Service Charge	Monthly Customer Cost
Residential	$8.50 [$14.00[1]]	$17.99
Firm Commercial	$20.00	$31.89
Small Interruptible	$75.00	$71.30
Large Interruptible	$275.00	$138.47

In establishing these charges, the Company sought to balance the following primary objectives:

- Match the customer related costs imposed by each class,
- Avoid large bill increases for any class or subclass of customers, and
- Maintain consistency with the monthly fixed charges proposed in the Company's current Minnesota gas rate case.

The proposed residential Basic Service Charge is the only charge that presently significantly deviates from cost. The Company is proposing a relatively low charge compared to cost for two reasons:

1. Setting the charge at the cost-based level would impose a significant percentage bill increase on low-use customers, and
2. The adoption of the partial decoupling proposal partially addresses some of the shortcomings of an insufficient Basic Service Charge[1].

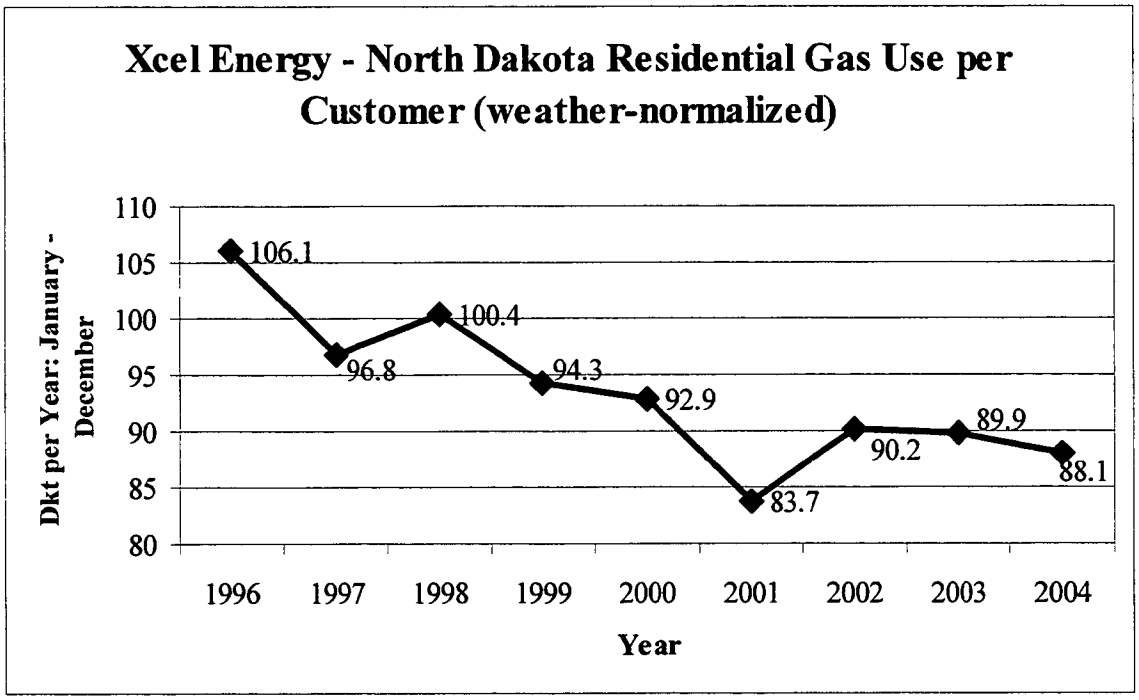
[1] In the alternative to an $8.50 Basic Service Charge combined with a partial decoupling mechanism, the Company proposes a $14 00 charge (without partial decoupling) See page 6 of this document.

C. *Partial Decoupling*

The Company also proposes to mitigate the impact on its recovery of fixed costs from the ongoing trend of declining use per customer. Specifically, the Company proposes to annually establish a "true up" factor to capture what residential customers would have paid had their class's weather-normalized use not deviated from the level used in this proceeding to set rates.

The chart below illustrates that in recent years the average use per North Dakota customer – particularly in the residential class, which constitutes 85% of Xcel Energy's natural gas customer base and 31% of our overall natural gas sales – has been steadily declining over time. This trend stems from:

- Improvements in appliance and equipment efficiencies due to new government mandates and new technologies;
- Improvements in building stock and changes in building codes that significantly lower energy use per square foot of space;
- New housing patterns, such as the significant trend to townhomes and multi-family housing, arrangements that provide significantly less revenue for a similar investment in distribution service equipment; and
- Fluctuations in wholesale natural gas pricing that influence customer consumption patterns.



Partial decoupling represents an important step towards allowing the Company to earn its authorized. We note, however, there are many factors that contribute to variations in bills and cost recovery. Among these factors are weather, changes in the number of customers, the overall economy, and changes in use per customer. By focusing only on declining use (weather-normalized) per customer, the Company is proposing to address only the last of these primary impacts on gas sales and revenues.

The Company's concern about the ongoing impact of declining use per customer cannot be overstated. Rates are set based on projected use per customer during the test year. As this use declines, all else being equal, the approved rates no longer allow the Company to recover its fixed costs of providing distribution service. Consequently, the proposed decoupling initiative is structured to mitigate the impact on the recovery of fixed costs from reductions in weather-normalized use per customer.

The Company's proposal is also conservative in that it is limited to the residential class. This class is projected to account for about 42%percent of the test-year distribution revenues collected through volumetric rates. For this reason the Company proposes to limit its partial decoupling proposal to the residential class. As the Company and Commission gain experience with partial decoupling, it could eventually be extended to other classes. In conjunction with the higher fixed charges discussed earlier, partial decoupling would markedly improve the Company's pricing.

The mechanism would be implemented through an annual residential rate adjustment effective September 1 of each year (as part of the existing annual true-up process). A proposed North Dakota Gas Rate Book Rider governing the conditions and implementation of the adjustment is included in Schedules 2 and 3.

D. Alternative Residential Rate Design

The Company strongly supports partial decoupling as an important component of a better rate design. But if the Commission has reservations about implementing a decoupling mechanism, then the Company's alternative recommendation is to impose a higher Basic Service Charge for the residential class. Specifically, the Company would propose a monthly charge of $14.00. This charge would recover about 78 percent of the monthly customer-related

costs imposed by a typical residential customer. The higher charge would replace, to some extent, the recovery otherwise afforded by partial decoupling.

While the alternative proposal would impose a relatively high percentage bill increase on very low-use customers, the actual monthly bill increase for these customers would not be as significant as these percentages suggest. Because these very low-use customers experience lower bills than the typical residential customer, any given percentage increase will have a smaller dollar impact on low-use customers than on the typical customer.

Other Tariff Changes

The Company is also proposing a number of miscellaneous tariff changes. The most significant changes are as follows:

- Eliminate the Gas Yard Lighting Service and Standby Service Rider because no customers are utilizing these services;
- Increase the limit on intra-day 1 nominations for Transportation customers and update the undertake/overtake cash-out provision for Transportation customers to provide flexibility for customers while minimizing "gaming" when wholesale natural gas price fluctuate;
- Refine the Main and Service Extension Policy and the methodology for calculating Winter Construction charges for purposes of clarity and improved matching of revenues with cost;
- Update the Limited Firm rate to capture current operational costs and the proposed distribution rate; and
- Update the charge for returned checks (unchanged since 1984).

These changes are reflected in the proposed tariff sheets included as Schedules 2 and 3.

Northern States Power Company d/b/a Xcel Energy
Gas Utility – State of North Dakota
Cost Allocation Summary

OPERATING REVENUES

Retail Revenues

Retail revenues are directly assigned based on the calculation of present rates (including a forecasted cost of gas) and forecasted sales. The Cost of Gas expense associated with these services is also directly assigned on this basis to match revenue and expense, consistent with the "matching" principle.

Other Operating Revenues

Retail revenues, as explained above, are used to allocate late payment revenues. Late-payment revenues are produced by non-payment of retail revenue.

Service connection revenues are allocated by number of customers, since establishment of service generally follows the same pattern of historic service.

Returned check charges are also allocated by the number of customers.

Gross earning taxes are allocated based on a historical-year collection of these costs.

Gas Agreement Revenues are allocated by design-day demand. These are primarily revenues from NSP (WI Co.) for its share of the dispatching charges under the intercompany SCADA and gas control services agreement.

Limited firm sales revenues are allocated by design-day demand, for the same reasons as opportunity sales. Again, the purchased gas expenses associated with these services are also allocated on this basis to match revenue and expense.

Opportunity sales are allocated by design-day demand. These revenues are primarily associated with sales routinely sold to other marketers and utilities, and are used to compensate firm customers for system pipeline capacity and other fixed costs that may be associated with these sales. The purchased gas expenses associated with these services are also allocated on this basis to match revenue and expense.

Other – Miscellaneous revenues are allocated on a combination of design-day and sales, because no direct allocator is available.

OPERATION AND MAINTENANCE EXPENSE

Cost of Gas Expenses

Expense associated with system sales are directly assigned. The Cost of Gas expense assigned matches the expense used to generate revenues as explained in the revenue section. Other purchased gas expense (not purchased gas expense paid to others) is allocated on sales, because no direct assignment is possible. Expense associated with opportunity sales is allocated based on design day to match associated revenues.

Production Expenses

Production expenses are allocated by peak-day demand, because LPG (propane) plants are primarily used for peak shaving. Liquified natural gas expense was allocated by 1/2 peak-day demand and 1/2 sales, reflecting the mixed use of this facility.

Transmission Expense

Items such as transmission, mains, services, etc., expenses are allocated in the same way as associated plant.

Distribution Expense

Items such as regulator stations, mains, services, etc., expenses are allocated in the same way as associated plant. Customer installation and other distribution costs are allocated based on the number of customers, reflecting that these expenses are affected by the size of the customer base. Dispatching is allocated by 1/2 sales and 1/2 peak day demand to reflect both the capacity and throughput aspects of dispatching. Supervision and engineering are allocated based on the sum of the distribution O&M accounts to reflect the underlying need for supervision and engineering.

Customer Accounting Expense

Allocated by a customer-weighted factor based on the average cost per customer for each class of customers.

Administrative and General

Some expenses, such as property insurance, injuries and damages, are allocated on a combination of gas plant in service and revenue, because no other direct allocator is available. Some other expenses (pensions and benefits, incentive compensation, and FAS 106- post retirement benefits) are allocated using the labor allocator, because these are primarily employee-related expenses.

The labor allocator is approximated by the sum of distribution, transmission, customer accounting, sales and customer service labor expenses. Finally, regulatory expenses are allocated on retail revenues, because such expenses are incurred in providing retail service.

Sales Expense

Sales expense is allocated by a study of sales expenses. These costs are primarily for sales advertising and outreach programs to customers. For advertising expenses, the Company included in the JCOSS only expenses recoverable under N.D. Admin. Code 69-09-01-29.

OTHER EXPENSES

Other plant related items are allocated based on the same factors as the associated gas plant in service or by an individual analysis of how the item is used. This includes items such as depreciation expense, taxes other than income taxes, and deferred income taxes.

Payroll taxes are allocated based on the labor allocator, while gross receipt taxes are allocated in the same way as the associated revenue.

INCOME TAXES

Income taxes are calculated by class, based on the allocated income statement produced by all the allocated expenses and revenues described above, and certain "Schedule M" adjustments described below.

Adjustments for Income Taxes (Schedule M adjustments)

Schedule M adjustments are allocated by the same methods as the associated gas plant (i.e. tax depreciation, interest expense). Other income adjustments for expenses such as post-retirement benefits, pensions, and insurance are allocated using the labor allocator. The labor allocator is approximated as the sum of distribution, transmission, customer accounting, sales, and customer service labor expenses. Other adjustments are allocated based on an individual analysis of the item.

REVENUE REQUIREMENT, RETURN ON EQUITY, ETC.

These items are derived on the basis of the allocated expenses, revenues, and rate base developed above.

RATE BASE ITEMS - GAS PLANT IN SERVICE

Production and Storage Plant
Production and storage plant costs are allocated by design-day demand. Production and storage plant are primarily used for peak shaving to meet design-day demand.

Transmission Plant and Regulator Station
Transmission plant and regulator station costs are allocated with the "average and peak" allocator. This method allocates costs to both firm and interruptible customers. This approach recognizes that transmission plant and regulator stations are built to serve two different functions: deliver gas all year round to all customers; and meet the peak day capacity needs of firm customers.

Therefore, the cost is split into two components. The component split is based on load factor. The average capacity component is equal to the average daily use of mains on the system and is allocated to all classes based on average demand (this allocator is equivalent to sales/ 365 days = average demand). The design day component is allocated based on the class contribution to the design day capacity that is above the average day capacity included in the average capacity component. Because interruptible customers are interrupted during a design day, they are not allocated any of the design-day costs.

Mains
A portion of the cost of mains is classified as a customer-related cost through the imputation of a minimum distribution system. This "minimum system" cost is based on the cost of plastic main of 2 inches in diameter or less. This cost (69.3% of the total cost) is then allocated to customer classes using the number of customers

The "average and peak" allocator described above is used to allocate the remaining costs (30.7% of the total).

Services, Meter and Regulators
Service, meter and regulator costs are allocated to each class of customers by a customer-weighted factor based on the average cost per customer of these facilities. The average cost is a relative weighting by class based upon a study performed for Xcel Energy's last rate case. This relative weighting is then multiplied by the number of customers to arrive at a class percentage. This percentage is used to allocate these costs.

General and Common Plant
General and Common plant costs are allocated based upon the allocation of the production, storage, and distribution components of plant.

RATE BASE ITEMS - OTHER

Other rate-base costs (e.g., accumulated depreciation reserve, accumulated deferred income taxes) are allocated based on either the same factors as the associated gas plant in service or through ananalysis of how the specific item is used.

CLASSIFICATION OF REV. REQUIREMENT TO SECONDARY COMPONENTS

Customer Related - Revenue Requirement

This portion of the revenue requirement is derived from classifying:

1) 100% of all rate base items associated with services, meters, house regulators, retail common and general plant;
2) a portion of common and general plant derived from the percentage of customer related plant;
3) expenses associated with those rate base items in (1) and (2) (including depreciation);
4) 100% of customer accounting expenses;
5) an allocated portion of costs such as administrative and general expenses; and
6) an allocated portion of other costs (e.g. taxes, return) derived on the basis on the allocated rate base and expenses developed in 1) - 5) above.

Capacity Related - Revenue Requirement

This portion of revenue requirement is derived from classifying:

1) rate base items associated with capacity such as a peak shaving, transmission, regulator station, and the non-customer related portion of mains;
2) a portion of common and general plant derived from the percentage of capacity related plant;
3) expenses associated with those rate base items (1) and (2) (including depreciation);
4) an allocated portion of costs such as administrative and general expenses;
5) a allocated portion of other costs (e.g. taxes, return) derived on the basis on the allocated rate base and expenses developed in (1) through (4) above; and
6) the demand costs associated with purchased gas.

Internal capacity revenue requirement (excluding 6 above) related items are further broken down into the following components.

- Peak shaving – capacity cost associated with the LNG and propane plants.
- Base capacity costs- primarily costs associated with the "average" portion of transmission, regulator stations, and mains.
- Seasonal capacity costs - primarily costs associated with the "peak" portion of transmission, regulator stations, and mains.

Energy Related - Revenue Requirement

This portion of the revenue requirement is derived from classifying every thing that is not included in the customer or capacity related portions of revenue requirement including the commodity portion of purchased gas expense. Generally this includes anything allocated by sales.

Equal Rate of Return

	Total Retail Rev Reqt	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Return On Rate Base			9 43%	9 43%	9 43%	9 43%	9 43%
2	Equalized Retail Revenue			70,122	29,646	29,995	3,554	6,926
3	Present Retail Revenue			68,841	26,637	31,114	3,845	7,245
4	Revenue Deficiency			1,281	3,009	-1,119	-291	-319
5	Deficiency / Pres Rev			1 86%	11 30%	-3 60%	-7 56%	-4 40%
	Internal Rev Reqt							
6	Customer Rev Reqt			9,943	7,460	2,350	94	38
7	Ave Monthly Customers			40,827	34,553	6,141	110	23
8	Rev Reqt $ / Mo / Cust			20 29	17 99	31 89	71 30	138 47
9	Capacity Rev Reqt			3,212	1,331	1,652	43	186
10	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
11	Rev Reqt $ / MCF (MCF per Month)			0 33	0 44	0 43	0 07	0 08
	Capacity - Sub Classification							
12	Capacity -Base Rev Reqt			715	225	283	43	164
13	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
14	Rev Reqt $ / MCF			0 07	0 07	0 07	0 07	0 07
15	Capacity -Seasonal Rev Reqt			1,213	533	658	0	22
16	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
17	Rev Reqt $ / MCF			0 12	0 18	0 17	0 00	0 01
18	Peak Shaving Rev Reqt			1,285	573	711	0	0
19	Ave Monthly Customers/ (Design Day)			9,788,919	3,018,662	3,800,041	616,604	2,353,612
20	Rev Reqt $ / MCF			0 13	0 19	0 19	0 00	0 00
12	Energy Rev Reqt			1,142	377	336	145	284
10	Annual MCF Sales			9,788,919	3,018,662	3,800,041	616,604	2,353,612
13	Rev Reqt $ / MCF			0 12	0 12	0 09	0 24	0 12
14	Total Internal Rev Reqt			14,297	9,168	4,337	282	509
15	Rev Reqt $ / MCF			1 46	3 04	1 14	0 46	0 22
	External Rev Reqt							
16	Capacity Rev Reqt			8,695	3,871	4,824	0	0
17	Rev Reqt $ / MCF			0 89	1 28	1 27	0 00	0 00
18	Energy Rev Reqt			47,130	16,607	20,834	3,272	6,417
19	Rev Reqt $ / MCF			4 81	5 50	5 48	5 31	2 73
20	Total External Rev Reqt			55,825	20,478	25,658	3,272	6,417
21	Rev Reqt $ / MCF			5 70	6 78	6 75	5 31	2 73
	Total Rev Reqt							
22	Cust Rev Reqt $ / MCF			1 02	2 47	0 62	0 15	0 02
23	Demd Rev Reqt $ / MCF			1 22	1 72	1 70	0 07	0 08
24	Ener Rev Reqt $ / MCF			4 93	5 63	5 57	5 54	2 85
25	Total Rev Reqt $ / MCF			7 16	9 82	7 89	5 76	2 94
26	Equalized Total Revenue			72,888	30,851	31,390	3,627	7,019
27	Present Total Revenue			71,607	27,842	32,509	3,918	7,338
28	Revenue Deficiency			1,281	3,009	-1,119	-291	-319
29	Deficiency / Pres Rev			1 79%	10 81%	-3 44%	-7 42%	-4 35%

Summary: Functionalized Rate Base

	Plant In Service	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Production	P10		1,660	741	919	0	0
2	Storage	P20		3,396	1,516	1,880	0	0
3	Transmission	P30		3,142	1,232	1,529	71	309
4	Distribution	P40		60,231	41,057	17,243	751	1,180
5	Sub-total	P60		68,429	44,547	21,571	822	1,489
6	General	P70		1,675	1,090	528	20	36
7	Common	P80		4,935	3,213	1,556	59	107
8	TBT Investment	PTBT		2	1	1	0	0
9	**Total**	PLANT		**75,041**	**48,851**	**23,656**	**901**	**1,633**
	Depreciation Reserve							
10	Production	A10		1,213	542	671	0	0
11	Storage	A20		2,439	1,089	1,350	0	0
12	Transmission	A30		1,721	675	838	39	169
13	Distribution	A40		23,745	16,348	6,657	287	453
14	Sub-total	A60		29,118	18,654	9,516	326	623
15	General	A70		969	621	317	11	21
16	Common	A80		2,595	1,662	848	29	55
17	**Total**	DEPR		**32,682**	**20,937**	**10,681**	**366**	**699**
18	**Net Plant With TBT**	NGPIS		42,359	27,914	12,975	536	934
	Accumulated Deferred Taxes	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
19	Production	DT10		28	12	16	0	0
20	Storage	DT20		155	69	86	0	0
21	Transmission	DT30		241	95	117	5	24
22	Distribution	DT40		5,175	3,528	1,482	65	101
23	Sub-total	DT60		5,599	3,704	1,700	70	125
24	General	DT70		190	126	58	2	4
25	Common	DT80		493	326	150	6	11
26	Non-Plant related	DT90		-339	-233	-89	-8	-9
27	**Total**	ADT		5,943	3,922	1,819	70	131
	Construction Work in Progress	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
17	Production	CP10		38	17	21	0	0
18	Storage	CP20		52	23	29	0	0
19	Transmission	CP31		11	4	5	0	1
20	Distribution	CP42		0	0	0	0	0
21	Sub-total	CP60		101	44	55	0	1
21	General	CP54		0	0	0	0	0
22	Common	CP64		0	0	0	0	0
23	Non-Plant related	CP90		0	0	0	0	0
24	**Total**	CWIP		101	44	55	0	1
	Net Investment Rate Base	**Input**	**Alloc**	**ND**	**Res**	**Sm C/I**	**Sm Int**	**Lg Int**
25	Production	NIRB10		457	204	253	0	0
26	Storage	NIRB20		854	381	473	0	0
27	Transmission	NIRB30		1,191	467	580	27	117
28	Distribution	NIRB40		31,311	21,181	9,105	399	625
29	Sub-total	NIRB60		33,813	22,234	10,410	426	742
30	General	NIRB70		516	344	154	7	11
31	Common	NIRB80		1,847	1,224	558	24	41
32	TBT Investment			2	1	1	0	0
33	Non-Plant related	NIRB90		339	233	89	8	9
34	**Total**	NIRB		36,517	24,036	11,211	466	804
	Additions							
35	Materials & Supplies	MSP		188	125	56	2	4
36	Gas in Storage	MSG		3,834	1,182	1,488	242	922
37	Non Plant Asset & Liabilities	NON		-574	-394	-152	-13	-15
38	Prepaids and Other	MISC		2,982	1,262	1,449	95	177
39	Cash Working Capital	WCASH		-549	-206	-221	-27	-95
40	**Total**			**5,881**	**1,970**	**2,620**	**299**	**993**
41	**Rate Base**	**BASE**		**42,398**	**26,006**	**13,831**	**764**	**1,797**

Summary: Income Statement

	ND	Res	Sm C/I	Sm Int	Lg Int
Operating Revenues					
Retail	68,841	26,637	31,114	3,845	7,245
Other Operating	2,766	1,205	1,395	73	93
Total Operating Revenues	**71,607**	**27,842**	**32,509**	**3,918**	**7,338**
Expenses					
Operating Expenses					
Purchased Gas (PGA)	55,825	20,478	25,658	3,272	6,417
Purchased Gas other	1,442	644	798	0	0
Production	724	258	323	30	113
Transmission	96	38	47	2	9
Distribution	1,664	1,169	445	19	31
Customer Accounting	1,200	1,015	180	3	1
Customer Service and Information	22	19	3	0	0
Administrative and General	1,458	941	429	37	51
Amortizations	20	8	9	1	2
Sales, Econ Develop & Other	131	57	10	53	11
Total O&Ms	**62,582**	**24,627**	**27,903**	**3,417**	**6,635**
Depreciation Expense	2,698	1,745	857	35	61
Taxes other than Income Taxes	1,165	758	368	15	25
Deffrred incomes Taxes and ITC	551	347	182	6	16
Gross Earnings	979	403	446	62	67
Op Income before taxes	3,632	(38)	2,753	382	534
State and Federal Income Taxes	408	(671)	773	134	172
Total Expense	**68,383**	**27,209**	**30,528**	**3,670**	**6,976**
AFUDC	-	-	-	-	-
Total Operating Income	**3,224**	**633**	**1,980**	**248**	**362**
Rate Base	**42,398**	**26,006**	**13,831**	**764**	**1,797**
Return on Rate Base	**7.603%**	**2.435%**	**14.319%**	**32.427%**	**20.158%**
Return on Equity at present rates	**7.865%**	**-2.423%**	**21.232%**	**57.275%**	**32.854%**
Required Rate of Return on Rate Base	**9.430%**	**9.430%**	**9.430%**	**9.430%**	**9.430%**
Required Operating Income	**3,998**	**2,452**	**1,304**	**72**	**169**
Income Deficiency	**774**	**1,819**	**-676**	**-176**	**-193**
Revenue Deficiency	**1,280**	**3,009**	**-1,119**	**-291**	**-319**
Percent increase indicated	**1.8%**	**10.8%**	**-3.4%**	**-7.4%**	**-4.3%**

Plant in Service

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	P10	Design Day	**1,660**	741	919	0	0
	Storage Plant							
2	LNG Storage	P20	Design Day	**3,396**	1,516	1,880	0	0
	Transmission Plant							
3	Transmission Plant	P30	Avg & Peak	**3,142**	1,232	1,529	71	309
	Distribution Plant							
4	Regulator Stations	P41	Avg & Peak	558	219	272	13	55
	Mains - Minimum System	P42A	Customers	20,828	17,627	3,133	56	12
5	Mains - Average Capacity	P42B	Avg & Peak	3,323	1,025	1,290	209	799
6	Mains - Excess Capacity	P42C	Excess Des Day	5,904	2,594	3,201	0	109
7	Mains - Total	P42		30,055	21,246	7,624	266	920
8	Services	P43	Serv Study	20,674	15,423	4,934	233	84
9	Meters	P44	Meter Study	7,981	3,551	4,089	232	109
10	House Regulators	P45	Regul Study	963	618	325	7	13
11	**Total**	**P40**		**60,231**	**41,057**	**17,243**	**751**	**1,180**
12	**Plant in Service w/o Gen and Com**	**P60**		**68,429**	**44,547**	**21,571**	**822**	**1,489**
	General Plant							
13	General Plant	**P70**	P60	**1,675**	**1,090**	**528**	**20**	**36**
	Common Plant							
14	Common Plant	**P80**	P60	**4,935**	**3,213**	**1,556**	**59**	**107**
15	Prelim Gas Plant	GPISA		75,039	48,850	23,655	901	1,633
16	TBT Investment	PTBT	Net Plant	2	1	1	0	0
17	**Gas Plant in Serv**	**GPIS**		**75,041**	**48,851**	**23,656**	**901**	**1,633**

Accumulated Depreciation Reserve

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	A10	Design Day	1,213	542	671	0	0
	Storage Plant							
2	LNG Storage	A20	Design Day	2,439	1,089	1,350	0	0
	Transmission Plant							
3	Transmission Plant	A30	Avg & Peak	1,721	675	838	39	169
	Distribution Plant							
4	Regulator Stations	A41	Avg & Peak	136	53	66	3	13
5	Mains	A42	Mains overall	11,849	8,376	3,006	105	363
6	Services	A43	Serv Study	8,646	6,450	2,063	98	35
7	Meters	A44	Meter Study	2,691	1,197	1,379	78	37
8	House Regulators	A45	Regul Study	423	271	143	3	6
9	**Total**	A40		**23,745**	**16,348**	**6,657**	**287**	**453**
10	**Accum Depr w/o Gen and Com**	A60		**29,118**	**18,654**	**9,516**	**326**	**623**
	General Plant							
11	General Plant	A70	A60	**969**	**621**	**317**	**11**	**21**
	Common Plant							
12	Common Plant	A80	A60	**2,595**	**1,662**	**848**	**29**	**55**
13	**Total Accum Depr**	**APD**		**32,682**	**20,937**	**10,681**	**366**	**699**
14	**Net Gas Plant Before TBT**	**NGPISA**		**42,357**	**27,913**	**12,974**	**536**	**934**
15	**Net Plant With TBT**	**NGPIS**		**42,359**	**27,914**	**12,975**	**536**	**934**

Subtractions to Net Plant (Page 1 of 1)

	Accum Defer Inc Tax Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	DT10	Design Day	28	12	16	0	0
	Storage Plant							
2	LNG Storage	DT20	Design Day	155	69	86	0	0
	Transmission Plant							
3	Transmission Plant	DT30	Avg & Peak	241	95	117	5	24
	Distribution Plant							
4	Regulator Stations	DT41	Avg & Peak	48	19	23	1	5
5	Mains	FT42	Mains overall	2,582	1,825	655	23	79
6	Services	DT43	Serv Study	1,777	1,325	424	20	7
7	Meters	DT44	Meter Study	686	305	351	20	9
8	House Regulators	DT45	Regul Study	83	53	28	1	1
9	**Total**	**DT40**		**5,175**	**3,528**	**1,482**	**65**	**101**
10	**ADIT w/o Gen & Com**	**DT60**		**5,599**	**3,704**	**1,700**	**70**	**125**
	General Plant							
11	General Plant	**DT70**	DT60	**190**	**126**	**58**	**2**	**4**
	Common Plant							
12	Common Plant	**DT80**	DT60	**493**	**326**	**150**	**6**	**11**
	Adjustments							
13	Accum Def Tax - TBT	DTTBT	Net Plant	27	17	8	0	1
14	Non-Plant Related	DTTTD	Labor	-366	-251	-97	-8	-10
15	**Total Inc Tax Lib Depr**	**DT00**		**5,943**	**3,922**	**1,819**	**70**	**131**
16	**Total Subtractions**	**ADT**		**5,943**	**3,922**	**1,819**	**70**	**131**

Additions to Net Plant (Pg 1 of 2)

	CWIP	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production	CP10	Design Day	38	17	21	0	0
2	LNG Storage Plant	CP20	Design Day	52	23	29	0	0
3	Transmission Plant	CP31	Avg & Peak	11	4	5	0	1
4	Distribution Plant- Mains	CP42	Mains overall	0	0	0	0	0
5	General Plant- Distribution	CP54	Dist Plant	0	0	0	0	0
6	Common Plant- Distribution	CP64	Dist Plant	0	0	0	0	0
7	**Total CWIP**	**CWIP**		**101**	**44**	**55**	**0**	**1**
	Materials & Supplies							
8	Materials and Supplies	MSP	Trans+Dist	188	125	56	2	4
	Gas In Storage							
9	LPG In Storage	MSGPN	Sales	272	84	106	17	65
10	LNG In Storage	MSGPM	Sales	499	154	194	31	120
11	NatGas Underground	SMGN	Sales	3,063	945	1,189	193	736
12	**Total**	**MSG**		**3,834**	**1,182**	**1,488**	**242**	**922**
	Non-Plant Assets & Liab							
13	Pension Liability	NON1	Labor	0	0	0	0	0
14	Accrued Vacation Reserve	NON2	Labor	0	0	0	0	0
15	Early Retirement Amortization	NON3	Labor	0	0	0	0	0
16	SFAS 106	NON4	Labor	0	0	0	0	0
17	SFAS 112	NON5	Labor	0	0	0	0	0
18	Deferred Gas Costs	NON6	Labor	0	0	0	0	0
19	All Other Adjustments	NON7	Labor	-574	-394	-152	-13	-15
13	**Total Non-Plt Assets & Liab**	**NON**		**-574**	**-394**	**-152**	**-13**	**-15**

Additions to Net Plant (Pg 2 of 2)

	Miscellaneous	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Prepay Insurance	PPI	Trans+Dist	85	57	25	1	2
2	Prepay Gas Reserv Fee	PPG	Design Day	1,181	527	654	0	0
3	Prepay Miscellaneous	PPM	Trans+Dist	44	29	13	1	1
4	Rate Case Exp Amort	RCAS	Pres Rev, Rev	0	0	0	0	0
5	Inc Tax Defer Inter Amort	ITD		0	0	0	0	0
6	Project 2000 Amortization	P2000		0	0	0	0	0
7	Customer Advances	CAD	Sales	-16	-5	-6	-1	-4
8	Other Working Capital	RCWO	Pres Rev, Rev	1,688	653	763	94	178
9	**Total**	**MISC**		**2,982**	**1,262**	**1,449**	**95**	**177**
	Working Cash							
10	Purchase Gas Exp - Commodity	WC11	Sales	-367	-113	-143	-23	-88
11	Purchase Gas Exp - Demand	WC12	Design Day	-60	-27	-33	0	0
12	Labor - Regular	WC13	Oper & Maint	-7	-3	-3	0	-1
13	Labor - Incentive Compensation	WC14	Oper & Maint	-5	-2	-2	0	-1
14	Pension and Benefits	WC15	Labor	-2	-1	-1	0	0
15	Payroll Taxes	WC16	Labor	-1	0	0	0	0
16	Other Operating Expenses	WC17	Oper & Maint	-17	-7	-7	-1	-2
17	Property Taxes	WC18	Orig1 Plant	-64	-42	-20	-1	-1
18	Gross Receipts Tax	WC19	Fees, Rev	-13	-5	-6	-1	-1
19	Federal Income Tax	WC20	Rt Bas w/o WC	-2	-1	-1	0	0
20	State Income Tax	WC21	Rt Bas w/o WC	0	0	0	0	0
21	State Sales Tax	WC22	Pres Rev, Rev	-11	-4	-5	-1	-1
22	**Total Working Cash**	**WCASH**		**-549**	**-206**	**-221**	**-27**	**-95**
23	**Total Additions**	**ADDIT**		**5,982**	**2,014**	**2,675**	**299**	**994**
24	**Total Rate Base**	**BASE**		**42,398**	**26,006**	**13,831**	**764**	**1,797**
25	Customer Component			28,282	20,714	7,136	306	126
26	Capacity Component			9,542	3,886	4,822	156	677
27	Commod Component			7,924	1,406	1,877	302	995

Operating Revenue (Cal Month)

	Retail Revenue	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	**Present Retail Rev**	**R01**	**Direct**	**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
2	**Proposed Retail Rev**	**R01P**	**Direct**	**70,115**	**27,577**	**30,886**	**3,939**	**7,713**
3	Gross Reciept taxes	R04	**Direct**	**0**	0	0	0	0
4	Proposed Transportation	R05	Net Plant	0	0	0	0	0
5	Interdepart'l - Angus Anson	R06	Design Day	0	0	0	0	0
4	**Total Rate Rev: Present**	**R10**		**68,841**	**26,637**	**31,114**	**3,845**	**7,245**
	Other Operating Rev							
8	Late Pay Penalties	R21	Present Revs	131	51	59	7	14
9	Penalties - Non-Curtailment	R22	Sales	0	0	0	0	0
10	Connection Charges	R23	Customers	45	38	7	0	0
11	Return Check Charges	R24	Customers	2	2	0	0	0
12	Gross Reciept Taxes	R25	Direct	979	403	446	62	67
13	Gas Agreement	R28	Design Day	26	12	14	0	0
14	Locating Services	R29	Dist Expen	0	0	0	0	0
15	Balancing Services	R30	Sales	30	9	12	2	7
16	Ltd Firm Sales - Rsrvs & Vols	R31	Design Day	37	17	20	0	0
17	Standy Sales - Resrvs & Vols	R32	Design Day	0	0	0	0	0
18	LP Sales to Others - MN	R33	Design Day	0	0	0	0	0
19	Off-System Sales	R34	Design Day	0	0	0	0	0
20	Opportunity Sales	R35	Design Day	1,475	658	817	0	0
21	Contr In Aid Cons Tax Gross-Up	R36	CWIP	0	0	0	0	0
22	Other - Miscellaneous	R37	DsnDay+Sales	41	15	19	1	5
23	**Tot Other Op - Present**	**R20**		**2,766**	**1,205**	**1,395**	**73**	**93**
26	**Tot Oper Rev - Present**	**R00**		**71,607**	**27,842**	**32,509**	**3,918**	**7,338**

Operation & Maintenance (Pg 1 of 2)

	Purchased Gas Expense	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Commodity	OXPGE	Direct	47,130	16,607	20,834	3,272	6,417
2	Demand	OXPGD	Direct	8,695	3,871	4,824	0	0
3	Other Purchased Gas	OXOPG	Sales	0	0	0	0	0
4	Opportunity Sales	OXOSN	Design Day	1,424	636	788	0	0
5	Limited Firm	OXANG	Design Day	18	8	10	0	0
6	**Total Purchases**	**OXPG**		**57,267**	**21,122**	**26,456**	**3,272**	**6,417**
	Other Production Exp							
7	Gas Agreement - NSP(W)	OXOSA	Design Day	0	0	0	0	0
8	MGP	OXOSSN	Sales	360	111	140	23	87
9	Misc LPG Op Exp	OXLPN	Design Day	143	64	79	0	0
10	Misc LNG Op Exp	OXLPM	DsnDay+Sales	221	83	104	7	27
11	**Total Other Prod Exp**	**OXOP**		**724**	**258**	**323**	**30**	**113**
	Other Transmission Expense							
12	Other Trans Expense	OX30	Avg & Peak	96	38	47	2	9
	Distribution Expense							
13	Regulator Stations	OX41	Avg & Peak	42	16	20	1	4
14	Mains	OX42	Mains overall	277	196	70	2	8
15	Services	OX43	Serv Study	203	151	48	2	1
16	Meters	OX44	Meter Study	225	100	115	7	3
17	House Regulators	OX45	Regul Study	28	18	9	0	0
18	Other Property & Equip	OX46	Customers	1	1	0	0	0
19	Dispatching	OX47	DsnDay+Sales	86	32	40	3	10
20	Customer Installations	OX48	Customers	392	332	59	1	0
21	Other Distribution	OX49	Customers	240	203	36	1	0
22	Supervision & Engineering	OX50	DisExp w/o Sup	170	119	45	2	3
23	**Total Distribution**	**OX40**		**1,664**	**1,169**	**445**	**19**	**31**

Operation & Maintenance (Pg 2 of 2)

	Customer Accounting	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Customer Billing Exp	OXBE	Customers	1,142	967	172	3	1
2	Customer Acct Exp	OXCA	Customers	58	49	9	0	0
3	Customer Service & Info	OXSI	Customers	22	19	3	0	0
4	**Total**	**OXCASI**		**1,222**	**1,034**	**184**	**3**	**1**
	Admin & General							
5	Property Insurance	OXAGPI	Net Plant	47	31	14	1	1
6	Pension and Benefits - ESOP	OXAGPS	Labor	0	0	0	0	0
7	Pension and Benefits - Direct	OXAGBL	Labor	540	370	143	13	14
8	Incentive Compensation	OXAGB	Labor	99	68	26	2	3
9	Injuries and Claims	OXAGID	Plant+Reven	115	60	44	4	7
10	Regulation Expense	OXAGR	Pres Rev, Rev	17	7	8	1	2
11	Promotional Adv / Contrib Adj	OXADV	Plant+Reven	36	19	14	1	2
12	Direct Assigned	OXDIR	Plant+Reven	191	99	73	6	12
13	Misc. Labor Adjustments	OXAGBS	Labor	439	301	116	10	11
14	Non-Regulated Exp Credits	OXCRED	Plant+Reven	-26	-13	-10	-1	-2
15	**Total A & G Expense**	**OXAG**		**1,458**	**941**	**429**	**37**	**51**
	Amortizations							
16	CIP / DSM Amortization	OXCIP	Sales MCF	0	0	0	0	0
17	MN Energy Policy Rider	OXCLN	Sales MCF	0	0	0	0	0
18	Rate Case Exp Amort	RCA	Pres Rev, Rev	20	8	9	1	2
19	Inc Tax Defer Inter Amort	ITDA	Rt Bas w/o WC	0	0	0	0	0
20	Project 2000 Amortization	P2A	Plant+Reven	0	0	0	0	0
21	**Total Amortizations**	**OXC**		**20**	**8**	**9**	**1**	**2**
	Sales Expense							
22	Gross Sales Expense	OXSALX	Sales Exp Study	131	57	10	53	11
23	Sales Expen Exlcusions	OXSEE	Sales Exp Study	0	0	0	0	0
24	Economic Develop @50%	OXSED	DsnDay+Sales	0	0	0	0	0
25	Other Misc - TBT	OXTBT	Net Plant	0	0	0	0	0
26	**Total**	**OXSE**		**131**	**57**	**10**	**53**	**11**
27	**Total O&M Expense**	**OXT**		**62,582**	**24,627**	**27,903**	**3,417**	**6,635**

Book Depreciation

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	DX10	Design Day	37	17	20	0	0
	Storage Plant							
2	LNG Storage	DX20	Design Day	64	29	35	0	0
	Transmission Plant							
6	Transmission Plant	DX30	Avg & Peak	95	37	46	2	9
	Distribution Plant							
7	Regulator Stations	DX41	Avg & Peak	18	7	9	0	2
8	Mains	DX42	Mains overall	931	658	236	8	28
9	Services	DX43	Serv Study	580	433	138	7	2
10	Meters	DX44	Meter Study	318	141	163	9	4
11	House Regulators	DX45	Regul Study	21	13	7	0	0
12	Lakes Area Surcharge	DX46	Dist Plant	0	0	0	0	0
13	**Total**	**DX40**		**1,867**	**1,252**	**553**	**25**	**37**
14	**Depreciation Expense w/o Com & Ge**	**DX60**		**2,063**	**1,335**	**655**	**27**	**47**
	General Plant							
14	General Plant	**DX70**	DX60	**111**	**72**	**35**	**1**	**3**
	Common Plant							
19	Common Plant	**DX80**	DX60	**524**	**339**	**166**	**7**	**12**
24	**Total Book Deprec**	**DX00**		**2,698**	**1,745**	**857**	**35**	**61**

Real Estate & Property Taxes

	Production Plant-	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PT10	Design Day	37	16	20	0	0
	Storage Plant							
2	LNG Storage	PT20	Design Day	75	34	42	0	0
	Transmission Plant							
3	Transmission Plant	PT30	Avg & Peak	**37**	15	18	1	4
	Distribution Plant							
4	Regulator Stations	PT41	Avg & Peak	8	3	4	0	1
5	Mains	PT42	Mains overall	421	298	107	4	13
6	Services	PT43	Serv Study	290	216	69	3	1
7	Meters	PT44	Meter Study	112	50	57	3	2
8	House Regulators	PT45	Regul Study	13	9	5	0	0
9	Other Prop & Equip	PT46	Dist Plant	0	0	0	0	0
10	**Total**	PT40		**844**	**575**	**242**	**11**	**17**
11	Real Est & Prop Taxes w/o Gen & Com	PT60		**993**	**640**	**322**	**11**	**20**
	General Plant							
18	General Plant	PT70	PT60	**2**	**2**	**1**	**0**	**0**
	Common Plant							
23	Common Plant	**PT80**	PT60	**7**	**5**	**2**	**0**	**0**
24	**Tot Rl Est & Pr Tax**	**PT0**		**1,002**	**646**	**325**	**11**	**20**
25	Gross Earnings Tax	GETX	Direct	979	403	446	62	67
26	Payroll Taxes	Z00	Labor	163	112	43	4	4
27	**Tot Non-Income Taxes**	**PTOT**		**2,144**	**1,161**	**814**	**78**	**92**

Provision For Deferred Income Taxes

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	PR10	Design Day	-3	-1	-2	0	0
	Storage Plant							
2	LNG Storage	PR20	Design Day	21	9	12	0	0
	Transmission Plant							
3	Transmission Plant	PR30	Avg & Peak	83	33	40	2	8
	Distribution Plant							
4	Regulator Stations	PR41	Avg & Peak	5	2	3	0	1
5	Mains	PR42	Mains overall	285	201	72	3	9
6	Services	PR43	Serv Study	196	146	47	2	1
7	Meters	PR44	Meter Study	76	34	39	2	1
8	House Regulators	PR45	Regul Study	9	6	3	0	0
9	**Total**	**PR40**		**571**	**389**	**163**	**7**	**11**
10	**Provision w/o Gen & Com**	PR60		672	430	214	9	19
	General Plant							
11	General Plant	PR70	PR60	**-19**	-12	-6	0	-1
	Common Plant							
22	Common Plant	PR80	PR60	**45**	29	14	1	1
	Other							
29	All Other Adjustments	PR77	Labor	-117	-80	-31	-3	-3
	Total Other	**PR70**		**-117**	**-80**	**-31**	**-3**	**-3**
30	**Tot Prov For Defer**	**PR0**		**581**	**366**	**191**	**7**	**17**

Investment Tax Credit For Current Income

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	CI10	Design Day	0	0	0	0	0
	Storage Plant							
2	LNG Storage	CI20	Design Day	-1	0	-1	0	0
	Transmission Plant							
3	Tramsmision Plant	CI30	Avg & Peak	-2	-1	-1	0	0
	Distribution Plant							
6	Regulator Stations	CI41	Avg & Peak	0	0	0	0	0
7	Mains	CI42	Mains overall	-13	-9	-3	0	0
8	Services	CI43	Serv Study	-10	-7	-2	0	0
9	Meters	CI44	Meter Study	-4	-2	-2	0	0
10	House Regulators	CI45	Regul Study	0	0	0	0	0
11	**Total**	**CI40**		**-27**	**-18**	**-8**	**0**	**-1**
12	ITC w/o gen and Com	CI60	subtotal	**-30**	**-20**	**-9**	**0**	**-1**
	General Plant							
13	General Plant	CI70	CI60	**0**	**0**	**0**	**0**	**0**
	Common Plant							
14	Common Plant	CI80	CI60	**0**	**0**	**0**	**0**	**0**
15	**Tot ITC For Curr Inc**	**CI00**		**-30**	**-20**	**-9**	**0**	**-1**
16	**Gross Inv Tax Credit**	**DI5**		**0**	**0**	**0**	**0**	**0**
17	**Net Inv Tax Credit**	**DI00**		**-30**	**-20**	**-9**	**0**	**-1**
18	**Total Operating Exp**	**TOE**		**67,975**	**27,880**	**29,755**	**3,536**	**6,804**
19	**Op Inc Before Inc Tax**	**OPY**		**3,632**	**-38**	**2,753**	**382**	**534**

Tax Depreciation & Removal Exp Generated

	Production Plant	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	LPG Production Plant	TA10	Design Day	36	16	20	0	0
	Storage Plant							
2	LNG Storage	TA20	Design Day	118	53	65	0	0
	Transmission Plant							
3	Transmission Plant	TA30	Avg & Peak	**317**	124	154	7	31
	Distribution Plant							
7	Regulator Stations	TA41	Avg & Peak	34	13	16	1	3
8	Mains	TA42	Mains overall	1,820	1,287	462	16	56
9	Services	TA43	Serv Study	1,252	934	299	14	5
10	Meters	TA44	Meter Study	483	215	248	14	7
11	House Regulators	TA45	Regul Study	58	37	20	0	1
12	Other Property & Equip	TA46	Dist Plant	0	0	0	0	0
13	**Total**	**TA40**		**3,647**	**2,486**	**1,044**	**45**	**71**
14	**Tax Depreciation w/o Gen & Com**	**TA60**	Subtotal	**4,118**	**2,679**	**1,284**	**53**	**103**
	General Plant							
14	General Plant	TA70	TA60	**109**	**71**	**34**	**1**	**3**
	Common Plant							
23	Common Plant	TA80	TA60	**562**	**366**	**175**	**7**	**14**
24	Tax Benefit Transfers	TATBT	Net Plant	-125	-82	-38	-2	-3
25	**Total Tax Depreciation**	**TA00**		**4,664**	**3,033**	**1,454**	**60**	**117**

Present Return

	Inc Tax Additions	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
1	Total Book Depr Exp	DX00		2,698	1,745	857	35	61
2	Book Dep Cleared To Operating	DX99	Book Deprec	78	50	25	1	2
3	Provision for Deferred	PRO		581	366	191	7	17
4	Net Inv Tax Credit	DI00		-30	-20	-9	0	-1
5	Book Amortizations	NDDI	Net Plant	20	13	6	0	0
6	Connect Fees and Other	ND2B	Customers	81	69	12	0	0
7	Avoided Tax Interest	ND2ASP	CWIP	106	47	58	0	1
8	Tax Capitalized Leases	NDTC	Plant	0	0	0	0	0
9	Meals & Entertainment	NDME	Labor	3	2	1	0	0
10	TBT Net Expense	NDTBT	Net Plant	0	0	0	0	0
11	**Total Tax Additions**			**3,537**	**2,273**	**1,140**	**43**	**81**
	Inc Tax Deductions							
12	Tax Depr & Removal Exp	TA00		4,664	3,033	1,454	60	117
13	Debt Interest Expense	ND1	Rate Base	1,548	950	505	28	66
14	Other Timing Differerences	PRMPAG	Labor	-75	-51	-20	-2	-2
16	**Total**			**6,137**	**3,932**	**1,940**	**86**	**180**
17	**Taxable Net Income**	FSNI		**1,031**	**-1,696**	**1,954**	**339**	**434**
18	**Inc Tax (Pre-Credits), @39.55%**	TAX		**408**	**-671**	**773**	**134**	**172**
19	**Tax Credits**			0	0	0	0	0
20	**Fed & State Inc Tax**	**TAXES**		**408**	**-671**	**773**	**134**	**172**
21	**Total AFUDC**	**AFC**	**CWIP**	**0**	**0**	**0**	**0**	**0**
22	**Pres Return**	**RETR**	**;BASE**	**3,224**	**633**	**1,980**	**248**	**362**
23	**Pres Return on Rate Base**	**RTRT**		**7.60%**	**2.43%**	**14.32%**	**32.43%**	**20.16%**

Labor Allocator

336,490

	Labor Components	Input	Alloc	ND	Res	Sm C/I	Sm Int	Lg Int
24	Customer Billing	LAB1	Wtd Customer	3 4%	2 8%	0 5%	0 1%	0 0%
25	Customer Accounting	LAB2	Customer	10 8%	9 2%	1 6%	0 0%	0 0%
26	Cust Serv & Inform	LAB3	Customer	2 3%	2 0%	0 3%	0 0%	0 0%
27	Distribution	LAB4	Dist Expen	70 2%	49 3%	18 8%	0 8%	1 3%
28	Gas Storage - LNG	LAB5	DsnDay+Sales	5 4%	2 0%	2 5%	0 2%	0 6%
29	Production	LAB6	Other Produc	2 6%	0 9%	1 1%	0 1%	0 4%
30	Sales	LAB7	Sales Exp Study	2 9%	1 3%	0 2%	1 2%	0 2%
31	Transmission	LAB8	Design Day	2 4%	1 1%	1 4%	0 0%	0 0%
32	**Total**	LABOR		100 0%	68 6%	26 5%	2 3%	2 6%

EXTERNAL ALLOCATORS		ND	Res	Sm C/I	Sm Int	Lg Int
Customer Related						
1 Customers - B Basis	C10	40,827	34,553	6,141	110	23
%1 Customers - B Basis	C10	100 00%	84 63%	15 04%	0 27%	0 06%
2 Service Weighting (index)	C20		1 00	1 80	4 75	8 19
2 Weighted Service	C20	46,318	34,553	11,054	523	188
%2 Services Factor	C20	100.00%	74 60%	23 87%	1 13%	0 41%
3 Meter Factor Weighting (Index)	C21		1 00	6 48	20 47	45 95
3 Weighted Meter	C21	77,659	34,553	39,794	2,255	1,057
%3 Meter Factor	C21	100 00%	44 49%	51 24%	2 90%	1 36%
4 House Regulator Weighting (index)	C22		1 00	2 95	3 79	30 84
4 Weighted Regutalor		53,817	34,553	18,138	418	709
%4 House Regulator Factor	C22	100 00%	64 20%	33 70%	0 78%	1 32%
5 Sale expense Weighting	E03		0 000762	0 000762	0 222279	0 222279
5 Weighted Sales Expense	E03	61	26	5	24	5
%5 Sales Expense	E03	100 00%	43 44%	7 72%	40 40%	8 44%
6 Cust Acctg Weights	C10WTS	23	1	1	6	6
6 Weighted Customers	C10W	41,493	34,553	6,141	661	138
%6 Weighted Custs (Cust Acctg)	C10W	100 000%	83 274%	14 800%	1 593%	0 333%
Main Allocator						
Mains - Average Day (Sales)		26,819	8,270	10,411	1,689	6,448
Mains - Average Day (Sales)	Load Factor =	100 00%	30 84%	38 82%	6 30%	24 04%
(Transportation adder)						
Mains - Excess Design Day		56,828	24,971	30,809	0	1,047
Mains - Excess Design Day		100 00%	43 94%	54 22%	0 00%	1 84%
Mains Average and Peak		9,227	3,619	4,491	209	908
Average and Peak		100 00%	39.22%	48 67%	2 27%	9 84%
Mains overall		30,055	21,246	7,624	266	920
Mains overall		100 00%	70 69%	25 37%	0 88%	3 06%
Sales and Capacity Related						
6 Design Day	D10	74,462	33,242	41,220	0	0
%6 Design Day %	D10	100 00%	44 64%	55 36%	0 00%	0 00%
7 Sales MCF	E10	9,788,919	3,018,662	3,800,041	616,604	2,353,612
%7 Sales MCF	E10	100 00%	30 84%	38 82%	6 30%	24 04%
8 Sales MCF (Exc CIP exempt)	E10CIP	8,948,819	3,018,662	3,800,041	616,604	1,513,512
%8 Sales MCF	E10CIP	100 00%	33 73%	42 46%	6 89%	16 91%
9 Gross Receipts	GR10	1,068,746	440,304	486,820	68,064	73,558
%9 Gross Receipts	GR10	100 00%	41 20%	45 55%	6 37%	6 88%
%10 CIP Allocator	GR10	3,346	0	0	0	0
CIP Allocator	GR10	0 00%	0 00%	0 00%	0 00%	0 00%
11 LatePayment Revenues	LPY					
%11 LatePayment Revenues	LPY	100 00%	38 69%	45 20%	5 59%	10 52%
12 Present Rev		68,841	26,637	31,114	3,845	7,245
%12 Present Rev	R01	100 00%	38 69%	45 20%	5 59%	10 52%

			ND	Res	Sm C/I	Sm Int	Lg Int
INTERNAL ALLOCATORS							
1	Rate Base		42,398	26,006	13,831	764	1,797
%1	Rate Base	BASE-COL	100 000%	61 338%	32 622%	1 802%	4 238%
				100 000%	100 000%	100 000%	100 000%
2	Rate Base less Working Cash		39,965	24,950	12,603	696	1,715
%2	Rate Base less Working Cash	BASEWC	100 000%	62 431%	31 536%	1 742%	4 291%
			101	44	55	0	1
4	Construction Work In Progress	CWIP	100 000%	44 052%	54 629%	0 247%	1 072%
5	50% Design Day, 50% Energy	D10E10	100 000%	37 740%	47 089%	3 149%	12 022%
7	Book Depreciation	DX00	100 000%	64 694%	31 755%	1 295%	2 256%
8	50% Gross Plant, 50% Pres Rev	EGPRV	100 000%	51.896%	38 360%	3 393%	6 350%
9	Gas Plant In Service	GPIS	100 000%	65 099%	31 524%	1 201%	2 176%
9	Gas Plant In Service (w/o Gen and Common)	GPIS (B)	100 000%	65 099%	31 524%	1 201%	2 176%
10	Labor	LABOR	100 000%	68 567%	26 504%	2 325%	2 605%
11	Net Gas Plant In Svc (w/o TBT)	NGPIS(A)	100 000%	65 899%	30 631%	1 265%	2 205%
12	Dis O&M w/o Sup & Misc	OXDTS	1,494	1,050	400	17	28
12	Dist O&M (w/o Sup & Eng)	OX40(A)	100 000%	70 280%	26 746%	1 128%	1 845%
13	Other Production Expense	OXOP	100 000%	35 671%	44 610%	4 093%	15 625%
14	Oper & Maint Expense	OXT	100 000%	39 351%	44 586%	5 460%	10 602%
15	Distribution Plant	P40	100 000%	68 166%	28 628%	1 246%	1 959%
4	Transmission & Distribution	TD	63,373	42,290	18,772	822	1,489
4	Transmission & Distribution	TD	100 000%	66 731%	29 622%	1 297%	2 349%
17	Rev w/o Regul Exp, Col %'s	R02-COL	100 000%	41 918%	42 944%	5 137%	10 001%

CONSTANTS FOR REV CALCULATION

			Rate	Ratio	Wtd Cost
1	Long Term Debt		7.3300%	48 6530%	3 5663%
2	Short Term Debt		7 7400%	1 1070%	0 0857%
3	Debt Total		7 3392%	49 7600%	3 6520%
4	Preferred Stock		0 0000%	0 0000%	0 0000%
5	Common Equity		11 5000%	50 2400%	5 7776%
6	Required Rate of Return			100 0000%	9 4296%
7	MN Combined State & Fed Tax Rate	TAXRATE	39 55%		
8	1 / (1 - Tax Rate) Factor	ONEOVER	1 6542600		
9	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	0 6542600		

Northern States Power Company (Minnesota) d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Capitalization and Cost of Capital
(000's)

Capitalization:	Amount /1 (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
Long-Term Debt	$1,868,026	48 65%	7 33%	3 57%
Short-Term Debt	$42,511	1 11%	7 74%	0 09%
Long-Term and Short-Term Debt	$1,910,537	49 76%		3 65%
Preferred Stock	$0	0 00%	0 00%	0 00%
Net Common Equity	$1,928,985	50 24%	11 50% /2	5 78%
Total Equity	$1,928,985	50 24%		5.78%
Total Capitalization	$3,839,522	100 00%		9 43%

/1 All are average balances; long term and short term debt based on 12 month averages, common and preferred equity based on thirteen month balances

/2 Return on equity authorized in Case No PU 400-00-521

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Tony Clark	President
Susan E. Wefald	Commissioner
Kevin Cramer	Commissioner

IN THE MATTER OF THE NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY	CASE NO. PU-400-04-578 **ALTERNATIVE PETITION FOR INTERIM RATES**

A. Introduction

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") hereby submits to the North Dakota Public Service Commission ("Commission") this Alternate Petition for Interim Rates ("Petition") from its North Dakota retail gas customers, pursuant to North Dakota Century Code ("N. D. Cent. Code"), Section 49-05-06. The Company respectfully requests that the Commission authorize, on an interim basis, rate relief of $741,000 to be effective within 60 days, effective January 1, 2005.

B. Effective Date

The date of the submission of this Petition is November 2, 2004. The Petition is submitted as part of the Company's Notice of Change of Rates for Natural Gas Service ("Notice"). Pursuant to N. D. Cent. Code 49-05-06, Xcel Energy requests that, should the Commission suspend the operation of the general rate schedules that accompany the Notice, the proposed interim rates be made effective on January 1, 2005. The interim rates will be subject to refund if the

interim rate amounts are in excess of the final rates approved by the Commission plus reasonable interest at a rate to be determined by the Commission.

C. Description and Need for Interim Rates.

Xcel Energy is entitled to interim rate relief based on the Notice of Change of Rates for Natural Gas Service and its supporting schedules along with the supporting schedules attached to this Petition. The proposed interim rate increase applies to all of Xcel Energy's retail gas customers in the State of North Dakota. Interim rates are needed because the increased costs of service reflected in the Company's general rate Notice will be incurred on or before June 1, 2005, the anticipated effective date of the general rate increase should the Commission suspend the Notice. Without interim rate relief, Xcel Energy would be unable to recover these increased costs of service while the rates were suspended.

Schedules attached to this filing support the interim revenue deficiency of $741,000 for Xcel Energy's North Dakota natural gas utility operation. As required by statute and indicated in Schedules 4 and 5, Xcel Energy has removed from the interim rate request the recovery of costs that are not of the same nature and kind as allowed in the most recent rate proceeding (Case No. PU-400-00-521).

In addition, the return on equity requested for interim rates for Xcel Energy is 11.5 percent, the same as approved by the Commission in Xcel Energy's last rate case (Case No. PU-400-00-521).

The test year for Xcel Energy's general gas rate increase Notice is the calendar year ending 2004. The revenue requirement study in the general rate increase Notice shows an annual deficiency in revenue of $1,280,232 under present rates. Present rates, as referred to in this Petition, are the rates authorized by the Commission in its final order in Case No. PU-400-00-521. Xcel Energy is requesting an interim rate adjustment that would increase Xcel Energy's test year revenues (exclusive of separately collected revenues related to franchise fees or gross earnings taxes imposed by local governmental units) by $741,000 or a 1.1 percent increase above present retail gas sales revenues.

D. Interim Rate Schedules

The following rate schedules are proposed on an interim basis to be effective within 60 days:

- 3rd Revised Sheet No. 1 Residential Gas Service (401)
- 3rd Revised Sheet No. 2 Commercial & Industrial Service (403 and 410)
- 3rd Revised Sheet No. 3 Small Interruptible Service (404)
- 3rd Revised Sheet No. 5 Large Interruptible Service (405)

The rate schedules containing proposed interim rates are included along with this Petition as Schedules 1 and 2 (regular and legislative formats, respectively). No change has been made in the existing rate design. A uniform percentage increase that would provide an additional $741,000, on an annualized basis, in the non-gas revenues (i.e., Basic Service and Distribution Charge revenues) currently being recovered from each customer class would be applied.

E. Supporting Schedules and Workpapers

Schedules 3 through 6 of this Petition include the adjustments made to rate base, operating expense, and capital structure included in the general Notice to arrive at the operating income, rate base, capital structure and cost of capital, and revenue deficiency pertaining to the interim rate increase. These adjustments were made to exclude any items that are not of the same nature and kind as those allowed in the Commission order in Case No. PU-400-00-521, pursuant to N. D. Cent. Code 49-05-06, Subs. 2. The rate of return on equity filed in the general Notice is unchanged from the Commission's previously authorized level in the Company's most recent case, so no adjustment was necessary in that regard. Schedule 7 shows the jurisdictional cost of service study supporting the interim rate increase. Schedule 8 shows the calculation of the Interim Rate percent increase needed to collect the Interim revenue deficiency.

F. Interim Bills

Xcel Energy proposes to include an informational line on customer bills to communicate to customers that their bill includes the increase in rates associated with the interim rate request.

G. Surety for Refund

The Company respectfully requests that the Commission not require a bond to secure any projected refund. Xcel Energy submits as part of this Petition an Agreement and Undertaking regarding the Company's commitment to refund any interim rates determined by the Commission to be unreasonable.

H. Conclusion

Xcel Energy hereby submits this Alternative Petition for Interim Rates. If the Commission suspends the operation of the general rate schedules listed in the Notice under N. D. Cent. Code 49-05-06, the Company respectfully requests that the Alternate Petition for Interim Rates be promptly considered and accepted by the Commission, so that interim rate schedules can be effective on January 1, 2005. Interim revenues would be subject to refund pending final Commission action on the general rate increase Notice. Xcel Energy is not able to easily perform a mid-month rate change, and believes that the proposed implementation date is consistent with the statute.

Dated: November 2, 2004

Respectfully submitted,

Kent T. Larson
Vice President
Northern States Power Company d/b/a Xcel Energy

Subscribed and sworn to before
me this 2nd day of November, 2004

NATALIE MACZKA
NOTARY PUBLIC • MINNESOTA
MY COMMISSION EXPIRES
JANUARY 31, 2009

Notary Public

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Tony Clark	President
Susan E. Wefald	Commissioner
Kevin Cramer	Commissioner

IN THE MATTER OF THE NOTICE OF CHANGE IN RATES FOR NATURAL GAS SERVICE BY NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

CASE NO. PU-400-04-____

AGREEMENT AND UNDERTAKING

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "Company") in conjunction with the Notice of Change in Rates for Natural Gas Service filed with the North Dakota Public Service Commission ("Commission") makes the following unqualified agreement concerning refunding any portion of the increase in rates determined by the Commission to be unreasonable.

Pursuant to North Dakota Century Code 49-05-06, Subd. 4, Xcel Energy hereby agrees and undertakes to refund to its customers in North Dakota the amount, if any, collected during the interim rate period in excess of final rates, plus interest at the current rate as determined by the Commission, computed from the effective date of the interim rates throught eh date of refund.

In addition, Xcel Energy agrees to keep such records of sales and billings under the proposed interim rates as will be necessary to compute any potential refund.

This Agreement and Undertaking is made pursuant to authority granted by the Board of Directors of Northern States Power Company d/b/a/ Xcel Energy

Dated: November 2, 2004

By: Kent T Larson

Kent T. Larson
Vice President
Northern States Power Company d/b/a Xcel Energy

RESIDENTIAL SERVICE
RATE CODE 401

Section No 5
3rd Revised Sheet No. 1

AVAILABILITY
Available to any residential customer for domestic use of natural gas service

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	$5 50
Distribution Charge per Therm	$0.12480
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause

MONTHLY MINIMUM CHARGE
Basic Service Charge

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider.

LATE PAYMENT CHARGE
A 1.0% late payment charge will be added to the unpaid balance on date due

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

COMMERCIAL AND INDUSTRIAL SERVICE
RATE CODE 403 AND 410

Section No. 5
3rd Revised Sheet No 2

AVAILABILITY
Available to any commercial and industrial customer for general use of natural gas service

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit

RATE

Basic Service Charge per Month	$14 00
Distribution Charge per Therm	$0.11280
Cost of Gas Charge per Therm	Determined Monthly

DETERMINATION OF COST OF GAS
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause

MONTHLY MINIMUM CHARGE
Basic Service Charge

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A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

SMALL INTERRUPTIBLE SERVICE (Continued)
RATE CODE 404

Section No 5
2nd Revised Sheet No. 4

MONTHLY MINIMUM CHARGE
Basic Service Charge

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
If customer fails to curtail use of gas hereunder when requested to do so by Company, customer shall pay in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, or $1 00 per Therm of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due

PRIORITY CLASSIFICATION
Priority 1 shall have first priority Curtailment shall begin with Priority 8 and progress to Priority 1 Priority classifications are defined in the General Rules and Regulations.

TERM OF AGREEMENT
Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days' written notice by either party.

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No 5
4th Revised Sheet No. 5

AVAILABILITY
Available on an interruptible basis to a commercial or industrial customer whose maximum hourly requirements are in excess of 10 Therms, whose maximum daily requirements are 2,000 Therms or more, and who will agree.

1 To curtail use of gas whenever requested by Company,
2. To provide and maintain suitable and adequate alternate fuel capable standby facilities, and
3 To have access to sufficient standby alternate fuel for periods of curtailment of the delivery of gas sold hereunder

If a portion of a customer's gas usage is for processing or manufacturing, and curtailment would not be in violation of applicable codes, then requirements (2) and (3) above shall not apply to that portion If customer agrees to confine the use of natural gas for specified end uses under this rate to the months of April through October in any calendar year, requirements (2) and (3) above shall not apply However, any use under this rate is still curtailable at Company's option

CHARACTER OF SERVICE
Delivery of gas hereunder shall be subject to curtailment whenever requested by Company, such requests to be made as far in advance as possible

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Basic Service Charge per Month	$275 00
Distribution Charge per Therm	$0 04390
Cost of Gas Charge per Therm	Determined Monthly

INTERIM RATE ADJUSTMENT N
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges. N

(Continued on Sheet No 5-6)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
1st Revised Sheet No 10.2

ADDITIONAL CHARGE FOR UNAUTHORIZED USE OF GAS DURING SERVICE CURTAILMENT, INTERRUPTION, OR RESTRICTION

If customer fails to curtail, interrupt, or otherwise restrict use of gas hereunder when requested to do so by Company due to customer's interruption of gas supply upstream from Company's distribution system, customer shall pay, in addition to the appropriate above rates, the higher of (i) $1.00 per Therm, or (ii) an amount equal to any payment Company is required to make to its pipeline supplier under the terms of its town border contract as a result of such failure to curtail, interrupt, or otherwise restrict service. Such payments, however, shall not preclude Company from shutting off customer's supply of gas in the event of customer's failure to curtail use thereof when requested by Company to do so

CURTAILMENT CONDITIONS

On days when customer has gas available for delivery at the town border station, curtailment may result from capacity limitations on Company's distribution system or other operational consideration

TERM OF AGREEMENT

Service agreement shall be for a term of not less than one year Upon expiration of term, agreement continues in force until terminated by at least 30 days written notice by either party

COMPANY OBLIGATION TO SERVE

Upon termination of this service Company's obligation to provide service under any other rate schedule shall be consistent with the obligation to serve other new customers Rules and regulations defining Company's obligation are set out in Section 6 of this rate book

ADDITIONAL FACILITIES

The cost of any new facilities required to provide service under this rate shall be borne by the customer

RECEIPT GAS QUALITY

The gas to be delivered to Company by customer shall be of merchantable quality and shall meet the minimum quality standards established by the interstate pipeline company serving the community in which customer is located. Company may refuse to accept delivery of gas which does not meet this quality standard.

INTERIM RATE ADJUSTMENT N

A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N

LARGE COMMERCIAL FIRM TRANSPORTATION SERVICE
RATE CODE 415

Section No 5
2nd Revised Sheet No 13

AVAILABILITY
Available on a firm basis to a customer who has made arrangements to have gas other than Company system supply delivered to a Company town border station and whose maximum daily requirements are more than 2,000 Therms

CHARACTER OF SERVICE
Service shall be provided through a Company owned meter with telemetering or other automated meter reading capabilities installed Company may, at its option, take title to transportation gas if necessary to arrange interstate pipeline transportation to Company town border station.

THERM ADJUSTMENT
Customer's consumption in Ccf will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14.73 PSIA, and a gas temperature of 60 degrees Fahrenheit

SUPERCOMPRESSIBILITY ADJUSTMENT
For customers served at 25 PSIG or greater, an adjustment factor or correction device shall be used to correct gas consumption measurements for supercompressibility

RATE

Customer Charge per Month	$300 00	
	Minimum	Maximum
Demand Charge per Therm per Month of Billed Demand	$0 05790	$0.69600
Energy Charge per Therm	$0 00898	$0 03471

Unless otherwise agreed to, a five day notice of any change in the energy charge shall be provided

RESOURCE ADJUSTMENT
Customers receiving transportation service under a service agreement executed after May 1, 2001, will be subject to a Resource Adjustment surcharge equivalent to the environmental cleanup charge per therm applied to sales service rate schedules through the Cost of Gas True-up provisions of the Cost of Gas Rider. The Company will revise the surcharge annually on the effective date of the True-up factor change.

INTERIM RATE ADJUSTMENT
A 5 84% adjustment will be applied to each bill prior to the Cost of Gas Charge and any applicable surcharges N N

(Continued on Sheet No 5-13 1)

RESIDENTIAL SERVICE
RATE CODE 401

Section No 5
3rd Revised Sheet No. 1

AVAILABILITY
Available to any residential customer for domestic use of natural gas service

THERM ADJUSTMENT
Customer's consumption will be adjusted to reflect 1,000 Btu per cubic foot, base pressure of 14 73 PSIA, and a gas temperature of 60 degrees Fahrenheit.

RATE

Basic Service Charge per Month	$5 50	C
Distribution Charge per Therm	$0 12480	C
Cost of Gas Charge per Therm	Determined Monthly	N

DETERMINATION OF COST OF GAS T
Wholesale natural gas costs fluctuate due to market conditions, pipeline delivery and storage cost changes, and seasonal demand variations The Company's costs of purchasing delivered wholesale natural gas is determined each month as defined in the Purchased Gas Adjustment Clause. T

MONTHLY MINIMUM CHARGE
Basic Service Charge. T

SURCHARGE
In certain communities, bills are subject to the applicable surcharge provided for in the Surcharge Rider T

LATE PAYMENT CHARGE
A 1 0% late payment charge will be added to the unpaid balance on date due.

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COMMERCIAL AND INDUSTRIAL SERVICE
RATE CODE 403 AND 410

Section No 5
3rd Revised Sheet No 2

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RATE

Basic Service Charge per Month	$14.00	C
Distribution Charge per Therm	$0 11280	C
Cost of Gas Charge per Therm	Determined Monthly	N

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MONTHLY MINIMUM CHARGE
Basic Service Charge I

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SMALL INTERRUPTIBLE SERVICE (Continued)
RATE CODE 404

Section No. 5
2nd Revised Sheet No. 4

MONTHLY MINIMUM CHARGE ~~M~~
Basic Service Charge. ~~MT~~

ADDITIONAL CHARGE FOR USE OF GAS DURING CURTAILMENT
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INTERIM RATE ADJUSTMENT N
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LARGE INTERRUPTIBLE SERVICE
RATE CODE 405

Section No. 5
4th Revised Sheet No. 5

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Cost of Gas Charge per Therm	Determined Monthly	N

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(Continued on Sheet No 5-6)

INTERRUPTIBLE TRANSPORTATION SERVICE
(Continued)
RATE CODE 407

Section No 5
1st Revised Sheet No. 10 2

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RATE CODE 415

Section No 5
2nd Revised Sheet No. 13

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INTERIM RATE ADJUSTMENT N
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(Continued on Sheet No 5-13 1)

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Revenue Deficiency Summary - Interim Rate Petition
($000's)

Interim Petition
Schedule 3

Line No.	Description	General Rate Application	Change	Interim Rate Petition
1	Average Rate Base	$42,398	($2,747)	$39,651
2	Total Available for Return	$3,224	$21	$3,245
3	Overall Rate of Return (Line 2 / Line 1)	7.60%	0.58%	8 18%
4	Required Rate of Return	9 43%	-0.11%	9 32%
5	Operating Income Requirement (Line 1 x Line 4)	$3,998	($304)	$3,694
6	Income Deficiency (Line 5 - Line 2)	$774	($326)	$448
7	Gross Revenue Conversion Factor	1 654260	$0	1.654260
8	Revenue Deficiency (Line 6 x Line 7)	$1,280	($539)	$741
9	Retail Related Revenue Under Present Rates	$68,841	$0	$68,841
10	Percentage Increase (Line 8 / Line 9)	1 86%	-0 78%	1 08%

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Operating Income - Interim Rate Petition
(000's)

Interim Petion
Schedule 4
Page 1 of 2

Line No.	Description	General Rate Application Present Rates	Remove Charitable Contibutions	Remove Rate Case Expense	CWC Adjustment	Interim Rate Petition Present Rates
	Operating Revenues					
1	Retail	$68,678				$68,678
2	Transportation, Interdept'l	163				163
3	Other Operating	1,787				1,787
4	Gross Earnings Tax	979				979
5	**Total Operating Revenues**	$71,607				$71,607
	Expenses					
	Operating Expenses					
6	Purchased Gas	$57,267				$57,267
7	Other Production	724				724
8	Transmission	96				96
9	Distribution	1,664				1,664
10	Customer Accounting	1,142				1,142
11	Cust. Service & Information	80				80
12	Administrative & General (2)	1,458	(29)			1,429
13	Amortizations	20		(20)		0
14	Sales, Econ Dvlp & Other	131				131
15	Total Operating Expenses	$62,582	($29)	($20)		$62,533
16	Depreciation	$2,698				$2,698
	Taxes					
17	Property	$1,003				$1,003
18	Gross Earnings	979				979
19	Deferred Income Tax & ITC	551				551
20	Federal & State Income Tax	408	11	8	9	436
21	Payroll & Other	163				163
22	Total Taxes	$3,104	$11	$8	$9	$3,132
23	**Total Expenses**	$68,383	($18)	($12)	$9	$68,362
24	AFUDC	$0				$0
25	**Total Operating Income**	$3,224	$18	$12	($9)	$3,245

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Operating Income with Proposed Increase - Interim Rate Petition
(000's)

Line No.	Description	Interim Rate Petition Present Rates	Interim Rate Increase	Interim Rate Petition Proposed Rates
	Operating Revenues			
1	Retail	$68,678	$741	$69,419
2	Interdepartmental & Transportation	163		163
3	Other Operating	1,787		1,787
4	Gross Earnings Tax	979		979
5	**Total Operating Revenues**	$71,607	$741	$72,348
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$57,267		$57,267
7	Other Production	724		724
8	Transmission	96		96
9	Distribution	1,664		1,664
10	Customer Accounting	1,142		1,142
11	Customer Service & Information	80		80
12	Administrative & General	1,429		1,429
13	Amortizations	0		0
14	Sales, Econ Dvlp & Other	131		131
15	Total Operating Expenses	$62,533	$0	$62,533
16	Depreciation	$2,698	$0	$2,698
	Taxes			
17	Property	$1,003		$1,003
18	Gross Earnings	979		979
19	Deferred Income Tax & ITC	551		551
20	Federal & State Income Tax	436	293	729
21	Payroll & Other	163		163
22	Total Taxes	$3,131	$293	$3,424
23	**Total Expenses**	$68,362	$293	$68,655
24	AFUDC	$0	$0	$0
25	**Total Operating Income**	$3,245	$448	$3,694

Note: Revenues reflect calendar month sales

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Rate Base - Interim Rate Petition
(000's)

Interim Petition
Schedule 5
Page 1 of 1

Line No.	Description	General Rate Application Present Rates	Gas Clean-Up Amortization	Hedging	Interim Rate Petition Present Rates
1	Utility Plant in Service	$75,041			$75,041
2	Less. Reserve for Depreciation	$32,682			$32,682
3	Net Utility Plant in Service	$42,359	$0	$0	$42,359
4	Utility Plant Held for Future Use	$0			$0
5	Construction Work in Progress	$101			101
6	Less Accum. Def. Income Taxes	$5,943			5,943
7	Cash Working Capital	($549)			(549)
	Other Rate Base Items				
8	Materials and Supplies	$188			$188
9	Gas In Storage	3,834			3,834
10	Non-Plant Assets & Liabilities	(574)			(574)
11	Prepayments	962		(946)	16
12	Rate Case Expense Amortization	0			0
13	Gas Clean-Up Amortization	1,801	(1,801)		0
16	Customer Advances	(16)			(16)
17	Other Working Capital	235			235
18	Total Other Rate Base Items	$6,430	($1,801)	($946)	$3,683
19	Total Average Rate Base	$42,398	($1,801)	($946)	$39,651

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
2004 Test Year
Summary of Capitalization and Cost of Capital - Interim Rate Petition
(000's)

Capitalization:	Amount[1] (A)	Percent of Total Capitalization (B)	Cost of Capital (C)	Weighted Cost of Capital (D)
Long-Term Debt	$1,973,346	51 40%	7.33%	3.77%
Short-Term Debt	$42,511	1 11%	7.74%	0.09%
Long-Term and Short-Term Debt	$2,015,857	52 50%		3.85%
Preferred Stock	$0	0 00%	0 00%	0.00%
Net Common Equity[2]	$1,823,665	47 50%	11 50% [3]	5 46%
Total Equity	$1,823,665	47 50%		5 46%
Total Capitalization	$3,839,522	100 00%		9 32%

[1] All are average balances; long term and short term debt based on 12 month averages, common and preferred equity based on thirteen month balances.

[2] Pursuant to settlement in Case No PU 400-00-521, $105,320,000 of common equity has been transferred to long term debt

[3] Return on equity authorized in Case No PU 400-00-521

ROE = 9.12%
Deficiency = $741
% Increase = 1.08%
Required ROE = 11.50%

Northern States Power Company (Mn)
Gas Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2004 Rate Case Interim Test Year

Summary Reports

October 26, 2004

Printed 10/26/2004 2 00 PM

Rate Base Summary

		Total Company Gas			North Dakota Retail Gas			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	795,836	847,026	821,431	72,704	77,377	75,041	723,132	769,649	746,390
2	Depreciation Reserve	(340,180)	(369,926)	(355,053)	(31,329)	(34,034)	(32,682)	(308,851)	(335,892)	(322,371)
3	Net Utility Plant	455,656	477,100	466,378	41,375	43,343	42,359	414,281	433,757	424,019
4	C W I P	659	834	747	118	84	101	541	750	646
5	Accumulated Deferred Taxes	(62,585)	(68,608)	(65,597)	(5,652)	(6,234)	(5,943)	(56,933)	(62,374)	(59,654)
	Other Rate Base									
6	Cash Working Capital	(8,676)	(8,676)	(8,676)	(549)	(549)	(549)	(8,127)	(8,127)	(8,127)
7	Materials & Supplies	2,071	2,071	2,071	188	188	188	1,883	1,883	1,883
8	Gas In Storage	34,722	34,722	34,722	3,834	3,834	3,834	30,888	30,888	30,888
9	Non-Plant Assets & Liab	(7,163)	(6,676)	(6,920)	(593)	(556)	(574)	(6,570)	(6,121)	(6,346)
10	Prepaids & Other	2,648	2,648	2,648	235	235	235	2,413	2,413	2,413
11	**Total Rate Base**	**417,333**	**433,415**	**425,373**	**38,956**	**40,345**	**39,651**	**378,377**	**393,070**	**385,722**

Income Statement Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Operating Revenues			
1	Retail	659,264	68,678	590,586
2	Net Margin Weather Adjustment	0	0	0
3	Interdepartmental & Transportation	8,702	163	8,539
4	Other Operating	18,273	1,787	16,486
5	Gross Earnings Tax	7,536	979	6,557
6	**Total Operating Revenues**	**693,776**	**71,607**	**622,169**
	Expenses			
	Operating Expenses:			
7	Purchased Gas	534,510	57,267	477,243
8	Production	3,678	724	2,953
9	Transmission	869	96	773
10	Distribution	22,917	1,664	21,252
11	Customer Accounting	11,054	1,142	9,913
12	Customer Service & Information	5,961	80	5,881
13	Administrative & General	16,652	1,429	15,223
14	Amortizations	232	0	232
15	Sales, Econ Dvlp & Other	251	131	120
16	Total Operating Expenses	596,123	62,533	533,591
17	Depreciation	29,665	2,698	26,967
	Taxes:			
18	Property	13,234	1,003	12,232
19	Gross Earnings	7,536	979	6,557
20	Deferred Income Tax & ITC	5,691	551	5,140
21	State & Federal Income (see Page 3)	4,777	436	4,341
22	Payroll & Other	2,160	163	1,997
23	Total Taxes	33,398	3,131	30,267
24	**Total Expenses**	**659,186**	**68,362**	**590,825**
25	AFUDC	0	0	0
26	**Total Operating Income**	**34,590**	**3,245**	**31,344**

Income Tax Summary

		Total Company Gas	North Dakota Retail Gas	All Other
	Income Before Taxes			
1	Total Operating Revenues	693,776	71,607	622,169
2	less Total Operating Expenses	(596,123)	(62,533)	(533,591)
3	Book Depreciation	(29,665)	(2,698)	(26,967)
4	Taxes (Other Than Current Income)	(28,621)	(2,696)	(25,926)
5	**Total Before Tax Book Income**	**39,366**	**3,681**	**35,685**
	Tax Additions			
6	Book Depreciation	29,665	2,698	26,967
9	Book Depreciation Cleared To Operating	858	78	780
10	Deferred Income Taxes & ITC	5,691	551	5,140
11	Book Amortizations	20	20	0
12	Connection Fees	888	81	807
13	Avoided Tax Interest	1,157	106	1,051
14	Tax Capitalized Leases	0	0	0
15	Meals & Entertainment	38	3	35
16	TBT Net Expense	(3)	0	(3)
17	**Total Tax Additions**	**38,314**	**3,537**	**34,777**
	Tax Deductions			
18	Tax Depreciation & Removal Expense	50,107	4,664	45,443
19	Debt Interest Expense	16,390	1,528	14,862
20	Other Tax/Book Timing Differences	(520)	(75)	(445)
21	Net Preferred Stock Deduction	0	0	0
22	**Total Tax Deductions**	**65,977**	**6,117**	**59,860**
23	**State Taxable Income**	**11,704**	**1,101**	**10,603**
24	State Income Tax Rate	8 95%	7 00%	N/A
25	**Total State Income Taxes**	**1,047**	**77**	**970**
26	**Federal Taxable Income**	**10,657**	**1,024**	**9,633**
27	Federal Income Tax Rate	35 00%	35 00%	35 00%
28	**Total Federal Income Taxes**	**3,730**	**358**	**3,372**
29	**Total Federal & State Income Taxes**	4,777	436	4,341

Revenue Requirement & Return Summary

(Dollars in Thousands)

	2004 Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	7 3300%	51 3960%	3 7673%
2	Short Term Debt	7.7400%	1 1070%	0 0857%
3	Preferred Stock	0 0000%	0 0000%	0 0000%
4	Common Equity	11 5000%	47 4970%	5 4622%
5	**Required Rate of Return**			**9.3152%**

	Composite Income Tax Rates		
	State of North Dakota Tax rate		7 00%
	Federal Statutory Tax rate	35 00%	
	Federal Effective Tax Rate (1-State Rate * Fed Rate)		32 55%
	Total North Dakota Composite Tax Rate		**39.55%**
	Total Corporate Composite Tax Rate		**40.81%**

		Total Company Gas	North Dakota Retail Gas	All Other
	Rate of Return (ROR)			
6	Total Operating Income	34,590	3,245	31,344
7	Total Average Rate Base	425,373	39,651	385,722
8	**ROR (Operating Income / Rate Base)**	**8.13%**	**8.19%**	**8.13%**
	Return on Equity (ROE)			
9	Total Operating Income	34,590	3,245	31,344
10	Debt Interest (Rate Base * Weighted Debt Cost)	(16,390)	(1,528)	(14,862)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	18,200	1,718	16,482
13	Equity Rate Base (Rate Base * Equity Ratio)	202,040	18,833	183,207
14	**ROE (Earnings for Common / Equity Rate Base)**	**9.01%**	**9.12%**	**9.00%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Retu	39,624	3,694	35,931
16	Operating Income	34,590	3,245	31,344
17	Operating Income Deficiency	5,035	448	4,587
18	Revenue Conversion Factor (1/(1-Composite Tax Rate	1 68960	1 65426	N/A
19	**Revenue Deficiency (Income Deficiency * Conversion I**	**8,507**	**741**	**7,766**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	667,967	68,841	599,126
21	Revenue Deficiency	8,507	741	7,766
22	**Total Retail Revenue Requirements**	**676,474**	**69,582**	**606,892**
23	**Percentage Increase (Decrease)**	**1.27%**	**1.08%**	**1.30%**

Rate Base Detail - Cash Working Capital

				Total Company Gas			North Dakota Retail Gas			All Other	
	Expenses										
	Includable Expenses		**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Purchased Gas										
1	Purchases		40 25	534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
2	Subtotal Purchased Gas			534,510	21,514,032		57,267	2,304,989		477,243	19,209,043
	Labor & Related Costs										
3	Regular Payroll		13 79	32,344	446,018		2,721	37,523		29,623	408,496
4	Incentive Compensation		259 51	1,148	297,831		99	25,691		1,049	272,139
5	Pension & Benefits		29 79	4,916	146,447		354	10,546		4,562	135,901
6	Subtotal Labor & Related			38,407	890,296		3,174	73,760		35,233	816,536
7	All Other Operating Expenses		42 34	22,974	972,725		2,092	88,574		20,882	884,151
8	Property Tax		345 46	13,234	4,571,948		1,003	346,422		12,232	4,225,525
9	Employer's Payroll Taxes		19 66	2,160	42,459		163	3,198		1,997	39,261
10	Gross Earnings Tax		71 98	7,536	542,453		979	70,474		6,557	471,979
11	Federal Income Tax		37 00	3,730	138,007		358	13,262		3,372	124,746
12	State Income Tax		37 00	1,047	38,737		77	2,852		970	35,885
13	State Sales Tax Customer Billings		51 86	13,668	708,843		1,111	57,616		12,557	651,227
14	Total Expenses		46 17	637,267	29,419,501	44 71	66,224	2,961,147	46 33	571,043	26,459,354
15	**Net Annual Expense Amount**				80,601			8,113			72,489
	Revenues		**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
16	Computer Billing	100 00%	41 94	659,264	27,649,551		68,678	2,880,359		590,586	24,769,192
17	Hand Billed	0 00%	41 94	0	0		0	0		0	0
18	Retail Revenue Adjustments		41 94	0	0		0	0		0	0
19	Interdepartmental		0 00	7,104	0		10	0		7,094	0
20	Transportation		33 21	1,598	53,078		153	5,076		1,445	48,001
21	Late Payment		0 00	2,293	0		131	0		2,162	0
22	Meter Calibration Adjustment		41 94	159	6,668		41	1,720		118	4,949
23	Connect Charge		41 94	456	19,131		45	1,906		411	17,225
24	Return Check Charge		41 94	37	1,550		2	71		35	1,479
25	Rents - Gas Property		35 21	0	0		0	0		0	0
26	CIP - Lost Sales Margin		0 00	0	0		0	0		0	0
27	Gas Agreement		35 21	239	8,428		26	926		213	7,502
28	Locating Services		35 21	0	0		0	0		0	0
29	Balancing Service		35 21	30	1,056		30	1,056		0	0
30	Standby Sales Res & Vols		35 21	0	0		0	0		0	0
31	Limited Firm Sales - Res & Vols		35 21	917	32,272		37	1,301		880	30,971
32	Sales to Other - MN LP		35 21	0	0		(0)	(8)		0	8
33	Off System End User		35 21	0	0		0	0		0	0
34	Opportunity Sales		35 21	14,042	494,419		1,475	51,935		12,567	442,484
35	CIAC Gross-Up		0 00	0	0		0	0		0	0
36	Agency Service		0 00	0	0		0	0		0	0
37	Other Gas Revenue		41 94	100	4,197		0	0		100	4,197
38	Total Revenues		41 20	686,240	28,270,351	41 69	70,628	2,944,342	41 14	615,612	25,326,009
39	Net Annual Amount				77,453			8,067			69,386
40	Expense / Revenue Factor				0 928636048			0 937639773			
41	**Allocated Revenue Amount**				71,926			7,564			
42	**Net Cash Working Capital**		Page 1 - Line 6		(8,676)			(549)			(8,127)

Northern States Power Company d/b/a Xcel Energy
Gas Utility - State of North Dakota
Interim Rate Increase Calculations

Interim Petition
Schedule 8
Page 1 of 1

Class	Item	Unit	Quantity	Unit Margin	Current Margin	Interim Increase *	Margin Increase
Residential -	Cust	Bill	16,037	$5 50	$88,204		
without space heating	Comm	Thm	361,520	$0 12480	$45,118		
	Total				$133,322	$7,791	5 84%
Residential -	Cust	Bill	398,604	$5 50	$2,192,322		
with space heating	Comm	Thm	29,825,100	$0 12480	$3,722,172		
	Total				$5,914,494	$345,628	5 84%
Commercial	Cust	Bill	4,023	$14 00	$56,322		
without space heating	Comm	Thm	1,652,070	$0.11280	$186,353		
	Total				$242,675	$14,181	5 84%
Commercial	Cust	Bill	69,666	$14 00	$975,324		
with space heating	Comm	Thm	36,348,380	$0 11280	$4,100,097		
	Total				$5,075,421	$296,594	5 84%
Sm Interruptible	Cust	Bill	1,322	$75 00	$99,150		
	Comm	Thm	6,166,040	$0 07310	$450,738		
	Total				$549,888	$32,134	5.84%
Large Interruptible	Cust	Bill	275	$275 00	$75,925		
	Comm	Thm	23,536,120	$0 04390	$1,033,236		
	Comm	Discount	10,879,170	-$0 03390	-$368,804		
	Total				$740,357	$43,265	5 84%
Retail Total					**$12,656,157**	**$739,593**	**5.84%**
Rate Total					**$12,656,157**	**$739,593**	**5.84%**
Late Pay @	0 1903%				$0	$1,407	
Other Op Rev					$0	$0	
Total Rev					**$12,656,157**	**$741,000**	**5.85%**

* Total interim increase was adjusted to reflect an increase in late payment revenues and then allocated to class based on current margin contribution

1718 S 19th St
GRAND FORKS, ND 58201

RECEIVED
AUG 30 2005
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

08-29-05

PUBLIC SERVICES COMMISSION:

RE: XCEL'S NATURAL GAS NOTIFICATION

IT APPEARS THAT THE PSC (IF REGULATORY INPUT IS YOUR CHARGE) HAS ALLOWED THE INCREASE TO BE SHIFTED FROM THE AFFLUENT/WASTEFUL/EGO-DRIVEN HOME OWNERS TO THE POORER/CONSERVATIVE/PRACTICAL SMALL HOME OWNER.

THIS IS THE RESULT of DETACHING THE DELIVERY CHARGE FROM USAGE. IT IS TRUE THAT LARGE AND SMALL HOMES BOTH HAVE METERS, BILLINGS, REPAIR, ETC. HOWEVER, THE DELIVERY WAS PREVIOUSLY LINKED TO USAGE. A $.20 RATE INCREASE APPLIED TO THERMS WOULD YIELD ABOUT THE SAME REVENUE. THE CHARGE IS NOW SIMPLY A FEE!!

AN EXAMPLE (EXCLUDING PRODUCT COSTS)

A) LAST YR 328 THERMS USED IN MY 1100 SQ. FT. HOUSE (ACTUAL)

		$
1) LAST YR	$5.50 BASIC X 12 MOS	66
2) LAST YR	$.125 DELIVERY X 328 THERMS	$41
		107
3) NEXT YR	$15.69 FLAT DELIVERY X 12 INCREASE	$188
		$81

B) HYPOTHETICAL 4000 SQ FT HOUSE USING 1400 THERMS

1) SAME AS ABOVE	$66
2) 1400 THERMS @ $.125	$175
	$241
3) NEXT YR SAME AS ABOVE $15.69 x 12	$188
DECREASE	<$73>

I FEEL THE UNHINGING OF DELIVERY CHARGES FROM USAGE WAS NOT OF ENVIRONMENTAL OR SOCIAL CONSCIOUSNESS BY THE PSC OR XCEL. THIS IS ANALOGOUS TO A COMPACT CAR DRIVER CONTRIBUTING A FEW CENTS PER GALLON OF GAS SO THE MOTOR HOME/SUV/ETC. CAN DRIVE MORE CHEAPLY. THINKING ABOUT IT, I GUESS, THAT'S EXACTLY WHAT IS HAPPENING!! BUT THAT'S ANOTHER VENUE/GOVERNMENT OVERSIGHT.

Sidney B. Bina
SIDNEY B. BINA
(701) 772-7240

C: Comm
Legal
Pud



XCEL ENERGY
NORTH DAKOTA RESIDENTIAL NATURAL GAS PRICES

(EFFECTIVE July 1, 2005)

Xcel Energy℠

RATE CHANGE

We're your energy partner and want to help you understand more about the natural gas services we offer and the rates you'll see on your energy bill

On July 1, 2005, we implemented a 1 1% overall increase in natural gas rates. The increase, only the second in 20 years, is needed to cover the increasing costs of delivering natural gas, including metering, billing, maintaining and upgrading the local distribution system

Also, a new natural gas Delivery Services charge replaces both the Basic Service and Distribution charges on your bill. This fixed monthly charge simplifies your bill, reduces monthly fluctuations and more accurately reflects the costs of delivering gas to you.

If you have additional questions, please call us at 1-800-895-4999

NATURAL GAS CHARGES

The amount of natural gas you use is shown on your bill in *therms*, which are measured units of 100 cubic feet (Ccf) of natural gas adjusted for pressure and heat content The items relating to natural gas service are listed below and appear on your bill under *Gas Charges*

Delivery Services Charge	$15 69
Cost of Gas Charge	varies monthly
Pressure Correction Adjustment	
Heat Content Adjustment	
City Fees	
Sales Tax	

DELIVERY SERVICES CHARGE

The Delivery Services Charge covers costs related to delivering natural gas to your home. Those costs are not dependent on how much natural gas you consume and include metering, billing and maintenance of equipment and your account Your monthly bill will always include this fixed Delivery Services Charge even if energy use for the month is zero

Detach and Retain This Portion For Your Records

Questions: Call 24 Hours 7 Days A Week or write to us at
Please Call **(800) 895-4999** Northern[illegible]es Power Company
Hearing Impaired **(800) 895-4949** PO BOX 8
Fax (800) 895-2895 EAU CLAIRE WI 54702-0008

Tired of writing check[illegible]oking for envelopes and stamps and making sure your payment is on time? Sign up for Auto Pay today Call us at 1-800-895-4999.

Billing Summary

Residential	
Previous Balance 06/26	$23 16
Payment Received as of 07/27	$23 16 CR
Balance As Of 07/27	**$0.00**
Current Energy Charges 07/27	$33 42
Total	**$33.42**

Averages for Billing Period	This Year	Last Year
Average Temperature	73*	69
Electric/kwh per Day	5 7	4 9
Cost per Day	$0 54	$0 41
Gas/therms per Day	0 1	0 1
Cost per Day	$0 58	$0 28

*** 4 Degrees Warmer**

Current Charges

Electric Charges Usage Period: 06/26/05 to 07/26/05
Invoice # 56372780
Residential Service 30 Days

Basic Service Chg	$4 72
Fuel Clause Adj 172 @ $0 011569	$1 99
Energy Charge Summer 172 kWh @ $0 062000	$10 66
Cntrld Air Cond Cr	$1 60 CR
Subtotal	**$15.77**
City Fees @2 00%	$0 31
Total Amount	**$16.08**

Meter Reading Information
Meter #000002081344

Company Reading on 07/26			9036
Company Reading on 06/26			8864
Total	**30 Days**	**kWh**	**172**

Gas Charges Usage Period: 06/26/05 to 07/26/05
Heat Content Adjustment 3 ccf x 1 0188 = 3 therms
Invoice # 22736269
Residential Service 30 Days

Delivery Services Chg	$14 33
Cost Of Gas 3 therms @ $0 746666	$2 24
Distribution Charge 0 41 therms @ $0 124800	$0 05
Interim Rate Adjumt	$0 04
Subtotal	**$16.66**

PRORATED →

Meter Reading Information
Meter #000000014516

Company Reading on 07/26			2899
Company Reading on 06/26			2896
Total	**30 Days**	**CCF**	**3**

1.88 SECOND PAGE

Xcel Energy

SIDNEY BINA
1718 S 19TH ST
GRAND FORKS, ND 58201-8115

Next Scheduled Meter Reading Date	Date Withdrawn	Amount Withdrawn
08/29/05	08/23/2005	$33.42

Your bill is paid through Xcel Energy's Auto Pay program On your due date, the amount is withdrawn from your financial institution and immediately credited

See back of bill for more information

Account #: 51-4144119-0

Statement Date: 07/27/05

Statement # 35677132

Premise # 302640865

Scott, Sandi L.

From: Lein, Jerry R.
Sent: Thursday, June 02, 2005 11 41 AM
To: 'brad w.erickson@xcelenergy com', 'james d thorsen@xcelenergy com
Cc: -Grp-PSC Commissioners; -Grp-PSC Legal, -Grp-PSC Public Utilities
Subject: NSP Gas Rate Increase Customer Contact

james.d.thorsen@xcelenergy.com;
The following contact was recorded into the Public Contact System:

Nathan Schwarz
2706 12th St S
Fargo ND 58103 Phone: 701 280-0850

The issue is as follows: Does not like increase in monthly service charge because it results in paying more for gas not used. Recently purchased energy efficient furnace and hot water heater and this lessens the savings expected from that investment.

The resolution so far is as follows: Explained the distribution delivery charge and the interim adjustment charges are being elliminated so that all Xcel distribution system operating revenue will be from the $15.69 customer charge - rest is paid to suppliers. Explained deregulation of gas costs and continuing upward market price trends due largely to increased electric generating demand, long term customer savings from eliminating company revenue fluctuations due to weather and declining use per customer. All he had heard on the radio was that the monthly charge was increasing from $5.50 to $15.69.
Additional Notes read as follows:
brad.w.erickson@xcelenergy.com;
james.d.thorsen@xcelenergy.com;

The issue is resolved as of 06/02/05 11:36
This issue is jurisdictional.

Lein

Scott, Sandi L.

From: Lein, Jerry R
Sent: Thursday, February 10, 2005 1 11 PM
To: -Grp-PSC Commissioners
Cc: 'james d thorsen@xcelenergy com', -Grp-PSC Legal, -Grp-PSC Public Utilities
Subject: NSP Gas Rate Increase NSP Gas

The following contact was recorded into the Public Contact System:

Doug Stensgrad
806 Heritage Circle
Fargo ND 58104 Phone: 701 238-0081

The issue is as follows: NSP gas rates are to high already. Requested increase should be denied. Is a landlord and gas bill is higher than what he collects in rent.

The resolution so far is as follows: Explained bill components and how wholesale costs NSP pays for purchased gas are not regulated but passed through the PGA to customers with no markup.
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

The issue is resolved as of 02/10/05 13:09
This issue is jurisdictional.

Lein

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Tuesday, February 08, 2005 9 08 AM
To: -Grp-PSC Commissioners, -Grp-PSC Legal; -Grp-PSC Public Utilities
Subject: FW Xcel NSP Gas Rate Filing Comment Volumetric Risk

From: Helbling, Sharon D.
Sent: Tuesday, February 08, 2005 9:03 AM
To: 'warrenrisom@verizon.net'
Subject: RE: Xcel NSP Gas Rate Filing Comment Volumetric Risk

Mr. Isom,

Thank you for your comments. We will place your comments in the Public Input File associated with this case.

The technical hearing will be held on April 20th in the Commission Hearing Room, 12th Floor of the Capitol Building, beginning at 1:30 CDT. You are welcome to attend if you wish.

From: Bauske, Shelly A.
Sent: Tuesday, February 08, 2005 8:55 AM
To: Helbling, Sharon D.
Subject: FW: Xcel NSP Gas Rate Filing Comment Volumetric Risk

-----Original Message-----
From: Warren R Isom [mailto:]
Sent: Monday, February 07, 2005 7:54 PM
To: ndpsc@state.nd.us
Cc: Brian O'Hearne
Subject: Xcel NSP Gas Rate Filing Comment Volumetric Risk

I am a member of the board of directors of the Weather Risk Management Association Mr OHearne, copied on this email, is president of the Weather Risk Management Association

We note

- Xcel's observation that its distribution costs in significant part are levied on volumes of gas consumed by North Dakota consumers
- Further, Xcel cites a secular reduction in volumes sold per customer due to the many conservation measures being implemented
- Xcel proposes a retroactive adjustment to rates in order to compensate Xcel for lower than expected volumetric consumption of gas

The Weather Risk Management Association, which is the market Association representing the market of companies which assume and trade weather risk, notes that the impact of weather is one major factor affecting year on year changes in volumes sold - i e weather risk is a significant source of volumetric change As a simple example, warm winters mean less volume of gas Risks of this sort can be managed efficiently on open financial markets

The weather component of the volatility in annual volumes sold can be managed by third parties who professionally take on weather risk as their normal business We ask why Xcel/NSP does not propose making use of this third party weather risk market to manage the weather related volumetric volatility

In managing the weather based volumetric volatility through risk transfer to third parties the cost of risk transfer would be known in advance of the season and the gas consumers of North Dakota would not be assuming this risk on behalf of their gas supplier We strongly believe that utilizing open, free market instruments to manage weather risk of this sort increases transparency of costs, increases predictability of the cost of a significant component of volumetric risk and provides an equitable distribution of this risk among Xcel/NSP, its consumers, and professional risk capital

Including weather risk in the volumetric adjustment forces Xcel/NSP's North Dakota customers to bear this risk and the associated volatility in gas costs We ask Xcel/NSP to make use of the open, free market to manage this portion of the volumetric risk proactively rather than to rely on its customers to absorb the adverse consequences of this risk retroactively

The North Dakota PSC will have received correspondence from the Weather Risk Management Association on this point.

Thank you.

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Wednesday, February 09, 2005 9 44 AM
To: 'Warren Isom
Cc: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Subject: RE Xcel NSP Gas Rate Filing Comment Volumetric Risk

Mr. Isom,

You are certainly welcome to attend the technical hearing in this proceeding. However, if you wish to participate in the hearing, you'll have to file a petition to intervene.

Sharon

-----Original Message-----
From: Warren Isom [mailto:isom_wr@willis.com]
Sent: Wednesday, February 09, 2005 8:10 AM
To: shelbling@state.nd.us
Cc: bohearne@guarnateedweather.com; leybov_mi@willis.com; william_windle@swissre.com
Subject: Xcel NSP Gas Rate Filing Comment Volumetric Risk

Thank you for your response to my email of Monday evening commenting on aspects of the Xcel NSP Rate filing. I expect that the Weather Risk Management Association is likely to take up your kind invitation to attend the technical hearing to be held on April 20 in Bismarck.

Permit me to compliment the PSC on the way it conducted this hearing and the manner in which it used the internet to facilitate public participation.

Again, thank you for your response and for extending the inviation to WRMA to attend the April hearing.

Warren R. Isom
Willis Re NY
phone 212 820 7608
cell 215 901 4981
fax 212 820 7694
email warren.isom@willis.com

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Scott, Sandi L.

From: Lein, Jerry R
Sent: Tuesday, February 01, 2005 5 53 PM
To: -Grp-PSC Commissioners, -Grp-PSC Public Utilities, -Grp-PSC Legal
Subject: FW NSP Gas Rate Increase NSP Gas

From: Thorsen, James D [mailto:james.d.thorsen@xcelenergy.com]
Sent: Tuesday, February 01, 2005 2:09 PM
To: Lein, Jerry R.
Subject: RE: NSP Gas Rate Increase NSP Gas

Jerry
Just an FYI on this one. An estimated gas reading went out on the 1/19/05 bill for 499 ccf. We were out and got an actual reading 1/31/05. The 1/19/05 gas billing was rebilled out at 343 ccf This is more in line with what they have used here in past years, 1/04 309 ccf, 1/03 365 ccf.

Jim Thorsen
Xcel Energy
701-795-5219
701-795-5280 Fax

-----Original Message-----
From: Lein, Jerry R. [mailto:jlein@state.nd.us]
Sent: Friday, January 28, 2005 5:33 PM
To: -Grp-PSC Commissioners; -Grp-PSC Legal; -Grp-PSC Public Utilities
Cc: Thorsen, James D
Subject: NSP Gas Rate Increase NSP Gas

The following contact was recorded into the Public Contact System

Gayle Smith
West Fargo
Phone· 701 282-0379

The issue is as follows Just got gas bill for $500 1100 sq foot house. Highest its ever been Xcel raping customers Bill keeps going up How are people expected to pay gas bills higher than mortgage payments Government needs to do something.

The resolution so far is as follows Explained costs of purchased gas from deregulated suppliers passed on dollar for dollar NSP only keeps customer charge and distribution delivery charge Thanked her for her comments and said I would pass them on to the Commissioners

Additional Notes read as follows
NSP contact james d thorsen@xcelenergy com,

The issue is resolved as of 01/28/05 17 31
This issue is jurisdictional.

Lein

Scott, Sandi L.

From: Lein, Jerry R
Sent: Friday, January 28, 2005 5 33 PM
To: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Cc: 'james d thorsen@xcelenergy com
Subject: NSP Gas Rate Increase NSP Gas

The following contact was recorded into the Public Contact System:

Gayle Smith
West Fargo
Phone: 701 282-0379

The issue is as follows: Just got gas bill for $500. 1100 sq foot house. Highest its ever been. Xcel raping customers. Bill keeps going up. How are people expected to pay gas bills higher than mortgage payments. Government needs to do something.

The resolution so far is as follows: Explained costs of purchased gas from deregulated suppliers passed on dollar for dollar. NSP only keeps customer charge and distribution delivery charge. Thanked her for her comments and said I would pass them on to the Commissioners.
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

The issue is resolved as of 01/28/05 17:31
This issue is jurisdictional.

Lein

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Thursday, January 27, 2005 8 53 AM
To: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Cc: 'dave sederquist@xcelenergy com
Subject: NSP Gas Rate Increase NSP Gas

;
The following contact was recorded into the Public Contact System:

Gail Fleming
721 6th Ave N
Fargo
Phone: 701-237-5145

The issue is as follows: She is unable to attend the Public Input hearings. She feels it's unfair for residential customers to bear the biggest impact and thinks it should be split fairly between business and residential customers.

The resolution so far is as follows: I thanked her for calling and told her I would relay her comments to the Commissioners and they would go into the Public Input file in the case.
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

This issue is not resolved.
This issue is jurisdictional.

Helbling

(1)

RECEIVED
JAN 26 2005
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Dear Sirs,

I am a retired man in early 60's, living on pension income (meager). In the past few years to fight the high cost of heat I put up 8 double storm windows on my house with hose shaped insulation between the storm window frames, I used snap clips or turnbuckles to hold the 2nd window on the house neatly. Last fall I added 2 more primed and painted and insulated windows to the main floor of my house. That completes the main floor. 2 more to go upstairs. (18 window on house)

Please refer to the bill enclosed. The price of heat has went up plenty. With a temperature decrease of only 1°, my bill went up $1.29 per day.

What would my bill be if I had not increased the number of windows between the outside from 48 to 68 and the number of screens from 18 to 20? - 2 had no screen

I also loosely "skirted" the base of my house with plywood and used window on the north and west side.

The neighbor to my north put up a 6' solid wood fence for his dog. That cuts —

I finished my first storm window in 1999 and installed my last storm window in 2004. Adding 50 screens for summer. Lives on Turnbuckles.

18 windows & screens
4 panes
48 to start
10 doubled up
20 additional Panes
+8 bare screen

48
+20 small
68 panes
+20 screens

C. Comm
Pipeline
Gas - Pipeline

I have stacked "stuff" against out walls inside house to help insulate in closets and bedrooms + basement. I do not save trash, garbage or refuse.

all paint + all insulation and extra windows scrounged in construction trash bins free

I also added rubber + plastic and fiber glass insulation to all the hot water pipes and hot water heat pipes in the basement.

The wind from the north somewhat.

I partly insulated the ceiling under my bedroom. The basement is only heated to 50°F. 1 Bedroom not heated, for storage

We deliberately let the hedges grow to 12' high on the north edge of my 50' lot to cut the winds also.

I shudder to think what the bill would be if I had done nothing.

Please reject completely any gas and electricity price increases.

Over the past 20 years ads in the paper said gas price would be stable regardless of world oil prices. We were lied to ??

I wish I had saved those ads.

I predicted when Excel energy took over Northern States Power Co that we would end up paying high prices like in big cities.

Let them increase by selling more product only.

Tell the price increasers to take a hike.

Vote no! now and over the next 20 years I vote for every homeowner in G.F.

Please save this letter, I cannot afford to write every year.

Donald M. Grasse
610 So. 9th St.
Grand Forks N.D. 58201

Amount of gas + electricity sold. ↕ Please check what prices were Jan. 1, 1995 to see how we are being gouged by greedy gas company.

Questions: Call 24 Hours / Days A Week
Please Call 1-800-895-4999
Hearing Impaired 1-800-895-4949
Fax 1-800-895-2895

or write to us at
Northern States Power Company
PO BOX 8
EAU CLAIRE WI 54702-0008

Moving? Be sure to call Xcel Energy at 1-800-895-4999 three weeks ahead of time to discontinue your old service and arrange for new

Billing Summary

Residential	
Previous Balance 11/30	$120 45
Payment Received As Of 12/27	$120 45CR
Balance As Of 01/03	**$ 00**
Current Energy Charges 01/03	$184 45
Total	**$184.45**

Averages for Billing Period	This Year	Last Year
Average Temperature	19*	20
Electric/kwh per Day	5 0	4 6
Cost per Day	$0 46	$0 40
Gas/therms per Day	4.6	4 5
Cost per Day	$4 97	$3 82

* 1 Degrees Colder

Current Charges

Electric Charges Usage Period: 11/29/04 to 01/02/05
Residential Service 34 Days

Basic Service Charge	$4 72
Energy Charge - Winter 169 kwh @ $ 054100	$9 14
Fuel Clause Adjustment 169 kwh @ ~~$ 007880~~	$1 33
Subtotal	**$15 19**
City Fees @ 2 00 %	$ 30
Total Amount	**$15.49**

Meter Reading Information
Meter #0002082405

Company Reading on 01/02			4973
Company Reading on 11/29			4804
Total	**34 Days**	**kwh**	**169**

Gas Charges Usage Period: 11/29/04 to 01/02/05
Residential Service 34 Days

Basic Service Charge	$5 50
Distribution Charge 156 therms @ $ 124800	$19 47
Interim Rate Adjustment (prorated)	$ 04
Cost Of Gas 156 therms @ $ 880684	$137 39
Subtotal	**$162.40**
City Fees @ 2 00 %	$3 25
State Tax @ 2 00 %	$3 31
Total Amount	**$168 96**

Meter Reading Information
Meter #0000374874

Company Reading on 01/02			1813
Company Reading on 11/29			1657
Total	**34 Days**	**ccf**	**156**

****Information only** 2004 State Taxes $15.89**

Xcel Energy

DONALD N MASSE
610 S 9TH ST
GRAND FORKS ND 58201

Next Scheduled Meter Reading Date	Date Due	Please Pay
02/01/2005	01/28/2005	$184.45

Account #: 0418-404-967

To avoid a late pay charge of 1% of the unpaid balance, payment of total amount must be received by due date.

See back of bill for more information.

Statement Date: 01/03/05 G 2666

1 2 4 11

UNDERSTANDING YOUR BILL

Basic Service Charge – A flat monthly charge that covers the customer costs associated with metering, billing and the maintenance of service lines, pipes and meters

City Fees – In the cities of Duluth, Xcel Energy collects a fee from customers. The fee is applied and shown separately on your monthly bill. Xcel Energy pays it directly to the city. It does not benefit Xcel Energy.

Therms – A Therm is a unit of heating value. When a cubic foot of gas has a heat content of 1,000 Btu, 100 gas equals one Therm. Gas rates are applied to Therms used in billing.

Distribution Charge (Gas) – A usage charge per Therm that covers only the delivery cost of natural gas to your home or business. It does not include the cost of the natural gas itself.

Base Cost of Gas (MN) – A charge that reflects the estimated cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via interstate pipelines.

Purchased Gas Adjustment (MN) – An estimate of the [illegible] cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via pipelines. The adjustment typically changes monthly due to conditions in the wholesale gas market and is included as part of the Minnesota Gas Resource Adjustment.

Conservation Adjustment (MN Gas) – The sum of the Purchased Gas Adjustment and a surcharge to recover the cost of mandated conservation programs designed to encourage customers to use energy efficiently. The surcharge is approved annually by Minnesota state regulators.

Cost of Gas (ND) – A charge that reflects the actual cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via pipelines. This charge typically changes each month due to conditions in the wholesale gas market.

Heat Content Adjustment – The Heat Content Adjustment accounts for differences in the heating content of natural gas and varies monthly. The higher the heat content of gas, the less gas you need to buy to achieve the same heating.

Pressure Correction Adjustment – The Pressure Correction Adjustment accounts for differences in the measured amount of gas calculated by different types of meters based on pressure delivered to your building.

Kwh – Kilowatt Hour is a unit of electrical usage. One Kwh equals 1,000 watts of electricity used for one hour. This lights a 100-watt light bulb for 10 hours.

Energy Charge (Electric) – A usage charge per Kwh that pays for most of the costs of generating, purchasing and delivering electricity to your home or business over company power lines.

Fuel Clause Adjustment – An adjustment to the electric bill to reflect increases or decreases in the cost of fuel (coal, nuclear, etc.) needed to run Xcel Energy generating plants, as well as the costs of purchasing electricity from other supplies.

Resource Adjustment (MN Electric) – The sum of the Fuel Clause Adjustment and a surcharge to recover the cost of mandated conservation programs designed to encourage customers to use energy efficiently. The surcharge is approved annually by Minnesota state regulators.

Estimate – Xcel Energy tries to read meters each month. If you have a meter inside your home that cannot be read, a card is left telling you how to read your own meter and then call us with that reading. If no reading is taken, Xcel Energy estimates your month's bill based on past use.

Processing Charge – This charge covers the costs associated with establishing a new customer account.

www.xcelenergy.com

AVOID ESTIMATED BILLS

Avoid estimated bills by allowing us access to indoor or obstructed meters on your reading date each month, provide a key to your premise or read your meter(s) and call in the reading using the dialer by the 20th of each month. Where your meters are indoors or obstructed, you may re-train your dog to the meter reader can read your meter.

ENVIRONMENTAL INFORMATION

Fuels used to generate electricity have different costs, reliability and air emissions. For more information, contact Xcel Energy at 1-800-895-4999 or online at www.xcelenergy.com. You can also contact the Minnesota Department of Commerce at www.commerce.state.mn.us or the Minnesota Pollution Control Agency at www.pca.state.mn.us/programs/electricity.html.

IMPORTANT CUSTOMER INFORMATION (Call the number listed on the front of this statement if you have questions or comments about your bill or our services)

Payment Responsibility
It is important that you check the name on the front of the bill. If the name is not that of a person or business who has payment responsibility, call us at 1-800-895-4999.

Late Payment Charge
Please pay your bill by the due date. Xcel Energy will assess a late payment charge on unpaid amounts two working days after the due date. Late payment charge provisions vary depending on the state in which your service is provided.

Governing Regulatory Agencies – State public utilities commissions regulate this service and are available for mediation.
Minnesota PUC: Consumer Affairs Office, 121 7th Place E., Suite 350, St. Paul, MN 55101-2147
North Dakota PSC: 600 E. Blvd., Bismarck, ND 58505 – (701) 328-2400
South Dakota PUC: Call (605) 773-3201

Questions· Call 24 Hours 7 Days A Week
Please Call 1-800-895-4999
Hearing Impaired 1-800-895-4949
Fax 1-800-895-2895

or write to us at
Northern States Power Company
O BOX 8
.U CLAIRE WI 54702-0008

Moving? Be sure to call Xcel Energy at 1-800-895-4999 three weeks ad of time to discontinue your old service and arrange for new.

Billing Summary

Residential	
Previous Balance 10/28	$57 38
Payment Received As Of 11/09	$57 38CR
Balance As Of 11/30	**$.00**
Current Energy Charges 11/30	$120 45
Total	**$120 45**

Averages for Billing Period	This Year	Last Year
Average Temperature	36*	23
Electric/kwh per Day	3 4	4 1
Cost per Day	$0 36	$0 38
Gas/therms per Day	3 0	4 1
Cost per Day	$3 29	$3 25

* 13 Degrees Warmer

Current Charges

Electric Charges Usage Period: 10/27/04 to 11/29/04

Residential Service 33 Days	
Basic Service Charge	$4 72
Energy Charge - Winter 113 kwh @ $ 054100	$6 11
Fuel Clause Adjustment 113 kwh @ $ 008360	$ 94
Subtotal	**$11.77**
City Fees @ 2 00 %	$ 24
Total Amount	**$12.01**

Meter Reading Information
Meter #0002082405

Company Reading on 11/29			4804
Company Reading on 10/27			4691
Total	**33 Days**	**kwh**	**113**

Gas Charges Usage Period: 10/27/04 to 11/29/04

Residential Service 33 Days	
Basic Service Charge	$5 50
Distribution Charge 100 therms @ $ 124800	$12 48
Cost Of Gas 100 therms @ $ 862509	$86 25
Subtotal	**$104.23**
City Fees @ 2 00 %	$2 08
State Tax @ 2 00 %	$2 13
Total Amount	**$108.44**

Meter Reading Information
Meter #0000374874

Company Reading on 11/29			1657
Company Reading on 10/27			1557
Total	**33 Days**	**ccf**	**100**

Xcel Energy asked the NDPSC for a natural gas increase of $2-3 monthly for the average residential customer. Interim rates take effect in January subject to refund. The PSC plans public input session in February. Look for details in January bills.

Xcel Energy

DONALD N MASSE
610 S 9TH ST
GRAND FORKS ND 58201

Account #: 0418-404-967

Next Scheduled Meter Reading Date	Date Due	Please Pay
01/03/2005	12/29/2004	$120.45

To avoid a late pay charge of 1% of the unpaid balance, payment of total amount must be received by due date

See back of bill for more information.

Statement Date: 11/30/04 G 2352

2 3 6 11

UNDERSTANDING YOUR BILL

Basic Service Charge – A flat monthly charge that pays for certain fixed costs associated with metering and billing and the maintenance of electric lines, gas pipes and meters.

City Fees – Some cities require Xcel Energy to collect a fee from customers. The fee is applied and shown separately on your monthly bill. Xcel Energy pays it directly to the city and makes no profit from the fee.

Therms – A Therm is a unit of heating value. All natural gas has the same amount of heat per cubic foot, so one Therm. Gas taxes are applied to the Therms used each billing.

Distribution Charge (Gas) – A usage charge per Therm that covers only the delivery cost of natural gas to your home or business through our distribution system. It does not include charges for the natural gas itself.

Base Cost of Gas (MN) – A charge that reflects the estimated cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via interstate pipelines.

Purchased Gas Adjustment (MN) – Adjustment to the Base Cost of Gas that reflects the actual cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via pipelines. This adjustment typically changes monthly due to conditions in the wholesale gas market and is included as part of the Minnesota Gas Recovery Adjustment.

Resource Adjustment (MN Gas) – The portion of the Purchased Gas Adjustment and a surcharge to recover the cost of mandated conservation programs designed to encourage customers to use energy efficiently. This surcharge is approved by the Minnesota Public Utilities Commission.

Natural Gas (ND) – A charge that reflects the cost of natural gas purchased from suppliers and delivered to Xcel Energy's pipeline. This charge typically changes each month based on changes in the wholesale gas market.

Fuel Clause Adjustment – The Fuel Clause Adjustment accounts for differences in the heating capability of natural gas and varies to provide the higher the heat content of gas, the less gas is required to produce the same heating.

Pressure Correction Adjustment – The Pressure Correction Adjustment accounts for differences in the measurement amount of gas calculated by different types of meters based on pressure differences in buildings.

Kwh – Kilowatt Hour is a unit of electric usage. One Kwh equals 1,000 watts of electricity used for one hour. For example, 100 watt bulb burned for 10 hours uses 1,000 watt hours or 1 Kwh.

Energy Charge (Electric) – A usage charge per Kwh that pays for the costs of generating or purchasing additional energy to meet customer demand.

Fuel Clause Adjustment – Adjusts monthly billings to recover the costs of fuel used to generate electricity. Fuel costs vary with the cost of coal, natural gas and purchased energy.

Transmission Adjustment (MN Electric) – The portion of the Fuel Clause Adjustment that recovers the costs of transmission lines and equipment that move electricity from generating plants to substations.

Electric Capacity Charge – The charge for the cost of building and maintaining power plants, transmission lines and substations.

Energy Charge – The charge for the cost of fuel used to generate electricity.

Demand Charge – The charge for establishing the maximum amount of power you may use at any one time.

AVOID ESTIMATED BILLS

Avoid estimated bills by allowing Xcel Energy access to your meter(s) on your regularly scheduled meter reading date each month. Please provide us a key if your meter(s) is behind a locked door or gate. Keep your dog restrained if you have one and be sure your meter(s) is clear of snow, ice, vehicles, trees, bushes and other obstructions.

SAFETY TIPS FOR YOUR HOME

Make sure your [illegible] are working properly. For more information on energy efficiency, visit Xcel Energy's website at [illegible]. Don't forget to [illegible] at least once a year. Don't store combustible [illegible] near your furnace or water heater.

IMPORTANT CUSTOMER INFORMATION (Call the number listed on the front of this statement if you have questions or comments about your bill or any charges.)

Payment Responsibility
It is important that you check the name on the front of the bill. If the name is not that of a person or business who has payment responsibility, call 800-[illegible].

Late Payment Charge
Please pay your bill by the due date. Xcel Energy will assess a late payment charge on unpaid amounts two (2) billing days after the due date. [illegible]

Governing Regulatory Agencies – [illegible] Commission regulates the [illegible] Minnesota [illegible]

[illegible]

Questions Call 24 Hours 7 Days A Week or Write to Us at

Please Call 1-800-895-4999 Northern States Power Company

Hearing Impaired 1-800-895-4940 O BOX 59

Fax 1-800-895-2895 INNEAPOLIS MN 55440-0059

Moving? Be sure to call Xcel Energy at 1-800-895-4999 three weeks ead of time to discontinue your old service and arrange for new.

Billing Summary

Residential	
Previous Balance 08/29	$57 21
Payment Received As Of 09/16	$57 21CR
Balance As Of 09/30	**$.00**
Current Energy Charges 09/30	$31 57
Total	**$31.57**

Averages for Billing Period	This Year	Last Year
Average Temperature	61*	64
Electric/kwh per Day	2 5	2 6
Cost per Day	$0 28	$0 28
Gas/therms per Day	8	6
Cost per Day	$0 70	$0 50

* 3 Degrees Colder

Current Charges

Electric Charges Usage Period: 08/28/03 to 09/29/03

Residential Service 32 Days

Basic Service Charge		$4 00
Energy Charge - Winter 79 kwh @ $ 054100		$4 27
Fuel Clause Adjustment 79 kwh @ $ 007360		$ 58
Subtotal		**$8.85**
City Fees	@ 2 00 %	$.18
Total Amount		**$9.03**

Meter Reading Information

Meter #0002082405

Company Reading on 09/29			3343
Company Reading on 08/28			3264
Total	**32 Days**	**kwh**	**79**

Gas Charges Usage Period: 08/28/03 to 09/29/03

Residential Service 32 Days

Basic Service Charge		$5.50
Distribution Charge 24 therms @ $ 124800		$3.00
Cost Of Gas 24 therms @ $ 548609		$13.17
Subtotal		**$21.67**
City Fees	@ 2 00 %	$ 43
State Tax	@ 2 00 %	$ 44
Total Amount		**$22.54**

Meter Reading Information

Meter #0000374874

Company Reading on 09/29			599
Company Reading on 08/28			575
Total	**32 Days**	**ccf**	**24**

Ask your customer service representative for Xcel Energy's guide to "60 Simple Ways to Save Money on Your Energy Bill." Inside you'll find 60 tips to help you identify which appliances in your home use the most energy - and how to use them more efficiently.

Xcel Energy

DONALD N MASSE
610 S 9TH ST
GRAND FORKS ND 58201

Account #: 0418-404-967

Next Scheduled Meter Reading Date	Date Due	Please Pay
10/29/2003	10/27/2003	$31.57

To avoid a late pay charge of 1% of the unpaid balance, payment of total amount must be received by due date

See back of bill for more information.

Statement Date: 09/30/03 G 2164

7 11

2 181

UNDERSTANDING YOUR BILL

Basic Service Charge – A flat monthly charge that pays for certain fixed costs associated with metering and billing and the maintenance of electric lines, gas pipes and meters

City Fees – Some cities require Xcel Energy to collect a fee from customers The fee is applied and shown separately on your monthly bill Xcel Energy pays it directly to the city and makes no profit from this fee

Therms – A Therm is a unit of heating value When a cubic foot of gas has a heat content of 1 0, a Ccf of gas equals one Therm Gas rates are applied to Therms used each billing

Distribution Charge (Gas) – A usage charge per Therm that covers only the delivery cost of natural gas to your home or business through our distribution system It does not include charges for the natural gas itself

Base Cost of Gas (MN) – A charge that reflects the estimated cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via interstate pipelines

Purchased Gas Adjustment (MN) – Adjustment to the Base Cost of Gas that reflects the actual cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy via pipelines The adjustment typically changes monthly due to conditions in the wholesale gas market and is included as part of the Minnesota Gas Resource Adjustment

Resource Adjustment (MN Gas) – The sum of the Purchased Gas Adjustment and a surcharge to recover the cost of mandated conservation programs designed to encourage customers to use energy efficiently The surcharge is approved annually by Minnesota state regulators

Cost of Gas (UC) – A charge that reflects the actual cost of natural gas purchased from wholesale suppliers and delivered to Xcel Energy It typically changes each month due to conditions in the wholesale gas market

Heat Content Adjustment – The Heat Content Adjustment accounts for differences in the heating capability of natural gas and varies monthly The higher the heat content is, the less gas you need to produce the same heating

Pressure Correction Adjustment – The Pressure Correction Adjustment accounts for differences in the measured amount of gas calculated by different types of meters based on pressure delivered to your building

Kwh – Kilowatt-Hour is a unit of electrical usage One Kwh equals 1,000 watts of electricity used for one hour This lights a 100-watt light bulb for 10 hours

Energy Charge (Electric) – A usage charge per Kwh that pays for most of the costs of generating, purchasing and delivering electricity to your home or business over company power lines

Fuel Clause Adjustment – An adjustment to the electric bill to reflect increases or decreases in the cost of fuel (coal, nuclear, etc) needed to run Xcel Energy generating plants, as well as the costs of purchasing electricity from other supplies

Resource Adjustment (MN Electric) – Consists of the Fuel Clause Adjustment and a surcharge to recover the cost of mandated conservation programs designed to encourage customers to use energy efficiently The surcharge is approved annually by Minnesota state regulators

Estimate – Xcel Energy tries to read meters each month If you have a meter inside your home that cannot be read, a card is left telling you how to read your own meter and what to do with that reading If no reading is taken, Xcel Energy estimates your month's bill based on past use

Processing Charge – This charge covers the costs associated with establishing a new customer account

www.xcelenergy.com

AVOIDING ESTIMATED BILLS

The best way to avoid an estimated bill is to make sure that we can read your meter on the next scheduled reading date, which appears on each month's bill. If you have an indoor meter and are not home, you may give us a key for monthly readings, or the meter reader will leave a card that will help you read your own meter Call or send the reading to your local Xcel Energy business office promptly, so we can avoid estimating your bill

You can help your meter reader by making sure there is a clear path to an outdoor meter and nothing blocking it from view Whether the meter is indoors or out, it's important to restrain your dog away from the meter

IMPORTANT CUSTOMER INFORMATION (Call the number listed on the front of this statement if you have questions or comments about your bill or our services)

Payment Responsibility
It is important that you check the name on the front of the bill If the name is not that of a person or business who has payment responsibility, call us at 1-800-895-4999

Late Payment Charge
Please pay your bill by the due date Xcel Energy will assess a late payment charge on unpaid amounts two working days after the due date Late payment charge provisions vary depending on the state in which your service is provided

Governing Regulatory Agencies – State public utilities commissions regulate this utility and are available for mediation.
Minnesota PUC Consumer Affairs Office, 121 7th Place E , Suite 350, St Paul, MN 55101-2147
North Dakota PSC 600 E Blvd , Bismarck, ND 58505 – (701) 328-2400
South Dakota PUC Call (605) 773-3201

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Thursday, January 13, 2005 10 41 AM
To: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Cc: 'dave sederquist@xcelenergy com
Subject: NSP Gas Rate Increase NSP

The following contact was recorded into the Public Contact System:

Doug Stensgard
806 Heritage Circle
Fargo ND
Phone: 701-238-0081

The issue is as follows: How can the Commission justify all these increases? He has rental property and the gas bills are almost as much as the rent he brings in. He pays what he can but keeps getting disconnects.

The resolution so far is as follows: I told him I would relay his concerns to the Commission. I also suggested he call NSP and work on some firm payment arrangements to avoid disconnect, rather than just paying what he wants when he wants.
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

The issue is resolved as of 01/13/05 10:40
This issue is jurisdictional.

Helbling

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Thursday, January 13, 2005 9 55 AM
To: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Cc: 'dave sederquist@xcelenergy com
Subject: NSP Gas Rate Increase NSP

The following contact was recorded into the Public Contact System:

Frankie Savage
1022 N 16th St-Fargo
2307 S 19th St
Moorhead MN
Phone: 218-236-7985

The issue is as follows: She owns a building in Fargo. She has no problem with increases relating to upgrading and maintenance. She does not feel she, an established customer, should have to pay for gas deliver to a growing customer base (they should pay for it). Also, she feels cost should go down when improving efficiency of the system. She's also wondering why the residential customers are taking the biggest hit.

The resolution so far is as follows: I told her I would relay her concerns to the Commission
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

The issue is resolved as of 01/13/05 09:53
This issue is jurisdictional.

Helbling

Scott, Sandi L.

From: Helbling, Sharon D
Sent: Tuesday, January 11, 2005 11 08 AM
To: -Grp-PSC Commissioners, -Grp-PSC Legal, -Grp-PSC Public Utilities
Cc: 'dave sederquist@xcelenergy com
Subject: NSP Gas Rate Increase NSP

The following contact was recorded into the Public Contact System:

Fargo ND

The issue is as follows: He's opposed to the increase. First reason given for increase: to provide distribution service to a continuing growing customer base (why should old people him pay for the new people who come in for service-they should be paying for it). A larger customer base should reduce the cost, not increase it. He wants to know if the Commission attempts to evaluate the efficiency of Xcel, i.e bosses, workers, overhead and how does it compare with other like companies. He sees too many people standing around watching while one person trims branches.

The resolution so far is as follows: He asked that I convey his message to the Commission. I assured him I would. He did not leave his name, address, or phone number.
Additional Notes read as follows:
NSP contact: james.d.thorsen@xcelenergy.com;

The issue is resolved as of 01/11/05 11:06
This issue is jurisdictional.

Helbling

11/23/04

RECEIVED
NOV 29 2004
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

~~Dear~~ To Whom it may Concern

I heard on the TV that ~~Excel~~ Xcel Energy has requested a rate increase. This letter is to let you know I am against it. A lady who works in the Housekeeping Office at the Holiday Inn doesn't think there is anyway of opposing it; it will be approved. Excel can raise their rate and it will have a multiplying effect for they do. The City of Fargo had to go to the polls to stop smoking in bldgs, why no go to using petitions in work places to see if people are interested in Excel raising their rate in ND.

Comm Regul

1015 - 5 AVENUE S.
Fargo, ND 58103

PU-04-578

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1 Article Addressed to

Kent L Larson
Northern States Power Company
414 Nicollet Mall
Minneapolis Mn 55401

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A Signature
X M Bailey ☐ Agent ☐ Addressee

B Received by (Printed Name) C Date of Delivery 6/6

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1. Article Addressed to:

Dale Sedquist
Xcel Energy
PO Box 2707
Fargo ND 58108-2707

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A. Signature
X ☐ Agent ☐ Addressee

B Received by (Printed Name) C Date of Delivery
Kathy Kay DEC 06 2004

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1. Article Addressed to.

Kent L Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Minneapolis Mn 55401

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A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) C Date of Delivery 12/6

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1. Article Addressed to:
James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis Mn 55401

COMPLETE THIS SECTION ON DELIVERY

A Signature
X [signature] ☐ Agent ☐ Addressee

B Received by (Printed Name) | C Date of Delivery
[signature] | 12/21

D Is delivery address different from item 1? ☐ Yes
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1. Article Addressed to:
James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis Mn 55401

COMPLETE THIS SECTION ON DELIVERY

A Signature
X [signature] ☒ Agent ☐ Addressee

B Received by (Printed Name) MARK TARNOWSKI | C. Date of Delivery 12/21

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1 Article Addressed to:
Kent L Larson
Northern States Power Company
414 Nicollet Mall 5th Fl
Minneapolis Mn 55401

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A Signature
X [signature] ☒ Agent ☐ Addressee

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[signature] | 12-21-04

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1 Article Addressed to

Dave Lederquist
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

COMPLETE THIS SECTION ON DELIVERY

A Signature
X [signature] ☐ Agent ☐ Addressee

B Received by (Printed Name) Matt Kaeb | C Date of Delivery DEC 20 2004

D Is delivery address different from item 1? ☐ Yes
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1. Article Addressed to:

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis Mn 55401

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B Received by (Printed Name) | C. Date of Delivery 3-14

D. Is delivery address different from item 1? ☐ Yes
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1 Article Addressed to

Dave Lederquist
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

COMPLETE THIS SECTION ON DELIVERY

A Signature
X [signature] ☐ Agent ☐ Addressee

B Received by (Printed Name) Matt Kaeb | C Date of Delivery MAR 14 2005

D Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below ☐ No

3 Service Type
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4 Restricted Delivery? (Extra Fee) ☐ Yes

2 Article Number (Transfer from service label) 7003 2260 0001 3517 9657

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1 Article Addressed to

Kent L Larson
Northern States Power Company
414 Nicollet Mall
Minneapolis Mn 55401

COMPLETE THIS SECTION ON DELIVERY

A Signature
X Ed. Larson ☐ Agent ☐ Addressee

B Received by (Printed Name) C Date of Delivery
MAR 1 5 2005

D Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below ☐ No

3 Service Type
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4 Restricted Delivery? *(Extra Fee)* ☐ Yes

2 Article Number
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1 Article Addressed to

James P Johnson
Xcel Energy Services Inc
800 Nicollet Mall Ste 2900
Minneapolis Mn 55401

COMPLETE THIS SECTION ON DELIVERY

A Signature
X Dane Sat ☑ Agent ☐ Addressee

B Received by (Printed Name) C Date of Delivery
6-6-05

D Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below ☑ No

3 Service Type
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4 Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7003 2260 0001 3516 8972

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1 Article Addressed to

Dave Ledergust
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

COMPLETE THIS SECTION ON DELIVERY

A Signature

X [signature] ☐ Agent ☐ Addressee

B Received by *(Printed Name)* | C. Date of Delivery

Matt Kay | NOV 22 2004

D Is delivery address different from item 1? ☐ Yes
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3 Service Type
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☐ Insured Mail ☐ C O D

4 Restricted Delivery? *(Extra Fee)* ☐ Yes

2 Article Number
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1 Article Addressed to

Dave Ledergust
Xcel Energy
PO Box 2747
Fargo ND 58108-2747

COMPLETE THIS SECTION ON DELIVERY

A Signature

X [signature] ☐ Agent ☐ Addressee

B ~~Received by~~ *(Printed Name)* | C Date of Delivery

Matt Kay | JUN 06 2005

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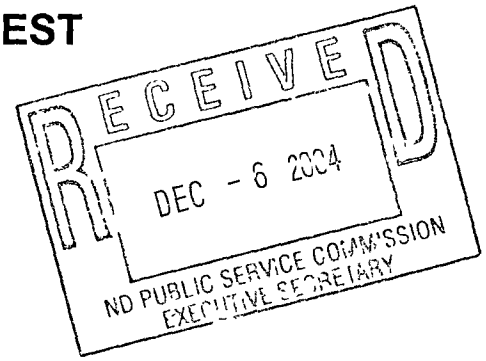
3. Service Type
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☐ Insured Mail ☐ C O D.

4 Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7003 2260 0001 3516 8958

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

RESPONSE TO REQUEST FOR PROPOSAL TO PROVIDE CONSULTING SERVICES TO THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE INVESTIGATION OF NORTHERN STATES POWER COMPANY'S GAS RATE INCREASE REQUEST



X Check for Original

CASE NO. PU-04-578

Submitted To:
Illona Jeffcoat-Sacco,
Executive Secretary
North Dakota Public Service Commission
600 Boulevard Ave. Dept 408
Bismarck, North Dakota 58505-0480
(701)328-2400

Submitted By:
Larkin & Associates, PLLC
15728 Farmington Road
Livonia, MI 48154
(734) 522-3420

December 6, 2004

24 PU-04 578 Pages 73
Proposal
by Larkin & Associates
12/06/2004 CC Comm Legal PUD (4) Mike

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I. BUSINESS ORGANIZATION

Larkin & Associates, PLLC

Larkin & Associates, PLLC is a firm of certified public accountants and regulatory consultants, with offices at 15728 Farmington Road, Livonia, Michigan 48154

Firm Background

In April 1970, the certified public accounting firm of Larkin, Chapski & Co , was formed by former employees of Peat, Marwick, Mitchell & Co , a big eight accounting and auditing concern. In addition to the auditing, accounting and tax work typical of CPA firms, Larkin, Chapski & Co, specialized in the area of utility regulation. In September 1982, the firm was reorganized into Larkin & Associates, a certified public accounting and consulting firm with Hugh Larkin, Jr , as senior partner As such, Mr. Larkin has the ultimate responsibility for all regulatory consulting work performed by the firm Section III of this proposal provides further details on the management of our utility regulatory project team. Larkin & Associates performs a wide variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. The firm has performed regulatory consulting services for numerous clients.

Larkin & Associates performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.) Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 300 regulatory proceedings.

Our project team is unusually well qualified to conduct this important study for the North Dakota Public Service Commission. We believe we satisfy the key ingredients for success of this assignment: strong technical skills, utility industry experience, relevant audit experience, extensive experience with natural gas utility rate and regulatory filings, an understanding of the regulatory environment, and demonstrated project management capability.

The distinct advantages of our approach include the following:

Maximum consulting skill applied to each assignment. The effective use of consultants rests on finding the best fit between the client's needs and the skill, knowledge, and experience of the individual consultants who actually work on the assignment. Our approach maximizes the productive time of the senior consultants who work on the engagement. Furthermore, we are not encumbered by the overhead necessary to support a large firm; consequently, our clients receive more pure consulting services for every dollar they spend.

Extensive utility industry experience. Collectively, the consultants available for our assignments have extensive and diverse experience with utilities and regulation. In addition to possessing the requisite professional skill, our project team brings together people with broad practical experience: The consultants we propose have meaningful prior experience in their field of specialization, which is the public utilities sector.

Proven technical skills Consulting is a skill-based professional service Our project team is made up of seasoned, career consultants who have climbed well up the experience curve at each functional discipline The methodologies we employ have been tested successfully on many engagements. We believe our approach provides the greatest probability of producing both useful and measurable benefits.

Value added approach. Our consulting philosophy emphasizes a collaborative approach. We strive to establish the closest possible working relationship with our client's personnel. We believe that the success of consulting engagements varies directly with the degree of client involvement. Therefore, we encourage our clients to become actively involved in our assignments.

Demonstrated project management capability. We consider project management to be an essential responsibility. We have substantial experience managing a full spectrum of consulting engagements, including many complex, large-scale projects. Senior consultants are responsible for providing direction to the project team, insuring that there is sufficient depth, detail, and balance to work plans. We use the detailed work activity plans and budgets to monitor progress and as a focal point for communications with the client.

Several CPAs on project team Our project team includes four seasoned CPAs and three CPA candidates, each of whom has devoted his or her career to addressing the issues affecting public utilities. In our extensive public utility consulting work, which encompasses management studies and rate case assistance, we stress the quantification of recommendations. Having several experienced CPAs on our team helps to insure that all of our recommendations are quantified, where possible, and that the underlying facts have been thoroughly verified.

Experience as expert witnesses. Project team members have presented testimony and have been cross-examined on numerous issues in regulatory proceedings. As a result of this experience, our team has a sharper appreciation of the value of rigorous fact verification and documentation of our findings and conclusions. We approach the investigative audit process with the type of discipline that enhances our ability to support our findings in subsequent regulatory proceedings, if and as necessary.

Expertise in developing spreadsheet models. Over the past several years, we have developed significant expertise in developing spreadsheet models to develop revenue

requirements and cost of service studies.

Experience with North Dakota utility regulation. Larkin & Associates has experience with North Dakota utility regulation, having assisted the Staff in a variety of utility regulatory projects.

Importance of this engagement. We can offer all of the talents and experience of a large consulting firm. At the same time, we are a small growing business where every client is very important. We strive to give each client a high degree of personalized care and attention. We anticipate being able to bring to this project, a valuable blend of big firm capabilities and small firm commitment, attention, and responsiveness

II. PROJECT SUMMARY

Approach to Scope of Work

The purpose of the contract will be to have Larkin & Associates, along with subcontractor Aaron Rothschild, provide comprehensive technical assistance to the North Dakota Public Service Commission ("PSC" or "Commission") Staff ("Staff") in analyzing the rate increase request made by Northern States Power Company (NSP)

Larkin & Associates will address issues pertaining to rate base, regulated net income and rate design. Aaron Rothschild will address the issue of cost of capital

The ultimate objective of this project involves presenting our conclusions and recommendations, in the form of oral testimony, before the Commission. We will assess, in light of the Commission's and Staff's regulatory philosophies and goals, an appropriate revenue requirement and rate base for NSP. We will determine a revenue requirement that can be effectively and convincingly supported at the proceeding In order to meet these objectives, we will perform a thorough review of the filings and supporting workpapers underlying the request for an increase in rates.

Throughout the project, a high degree of communication will be maintained among all members of the project team, as well as with PSC staff members assigned to the project. Communications will be facilitated by regular staff meetings, telephone conference calls, and if necessary, trips to North Dakota to meet with Staff personnel and review data.

Our findings will be presented first in the form of oral telephone discussions and monthly progress reports to PSC staff members working on the project. Upon completion of the analytical work, we will prepare and submit to the appropriate PSC staff members, drafts of testimony Then, after discussions with, and approval by these persons, our findings will be presented to the Commission in the form of written testimony and exhibits, to be followed with oral direct testimony and cross examination at the hearings. We will respond to interrogatories related to our scope of work issued by any parties to the proceeding. We will also analyze rebuttal testimony, prepare and assist in cross-examination procedures, and prepare and present oral testimony at the hearings In addition, we will provide PSC Staff with technical support at the hearings, and after the hearings, in preparing proposed findings of fact. In order to present a convincing and accurate case to the Commission, we will utilize to the fullest extent possible, our accumulated expertise in accounting, economics, finance, law, taxation, and utility ratemaking.

Functional Approach to Work Tasks

The work on this project will be divided into multiple tasks that provide a sensible, chronological series of expected activities, encompassing the required work areas within the established time constraints. The major tasks described below represent the anticipated approach to the overall scope of work. Interaction with Staff is anticipated to coincide with all tasks performed, to provide for substantial input by these persons, so as to optimize project team performance.

1 We will discuss with Staff assigned to the project, the specifics of the approach Staff wishes to follow in this case In this meeting, we will discuss the areas that are of particular concern. A time line will be agreed upon establishing all critical project deadlines.

2. We will perform a detailed review of the Company's filing in the current case, including its testimony and supporting workpapers. This will include a thorough analysis, review, and evaluation of all pertinent evidence filed on behalf of all parties in the current case. Additionally, we will review testimony, briefs, and orders of the Commission in prior cases to determine what issues were presented by the various parties, and how they were resolved by the Commission. Furthermore, we will determine if there are any new areas of concern that are raised by making a comparison to the testimony and order in the prior case. Based on this analysis, we will advise and recommend an approach to each specific issue.

3. We will conduct discovery of NSP, sufficient to conduct a complete analysis of the Company's case. This will include preparation of a comprehensive array of written requests for information as may be necessary for a thorough analysis of the case Our discovery files contain many standardized data requests designed to obtain the information necessary to thoroughly evaluate typical issues we have encountered in other rate cases. These standardized requests for information provide an efficient, effective starting point in developing the first set of discovery to be served upon the Company. Additionally, we develop Company-specific data requests to clarify issues, pinpoint problem areas, and obtain follow-up information, as well as address issues and quantifications unique to this Company and rate case.

4. Larkin & Associates will submit periodic progress reports in which we will update Staff of the conclusions and recommendations we have formulated based upon our review of NSP's response to discovery. Such progress reports will also advise Staff of any potential problems we foresee in meeting project deadlines.

5 We will carefully analyze and evaluate the information received in steps 1 through 4. All information gathered as well as analyses and evaluations will be performed in order to consider all possible issues, which come to our attention during the course of our review. Based upon this evaluation, we will discuss our findings with Staff to

determine which items should form the basis for proposed adjustments as part of our formal testimony.

6. We will submit drafts of testimony and exhibits in advance of the filing date so that Committee Staff and Counsel assigned to the project will be able to review them. We will thoroughly review, verify, and correct the draft testimony and exhibits to meet the satisfaction of the Committee in order to have finished copies ready for filing sufficiently in advance of the filing deadline.

7. We will assist Staff counsel with the preparation of cross-examination questions. Our tested and effective format for preparing cross-examination includes, for each issue, identification of the appropriate witness; a summary of the issue (what the Company did, why it may be inappropriate, impact on rates, and discussion of relevant discovery responses), specific cross-examination questions (primarily drafted to elicit a "yes" or "no" response to keep the witness on track) and anticipated witness responses.

8. For issues pertaining to rate base and regulated net income, Ralph Smith will present expert testimony and undergo cross-examination at the hearings. Ralph Smith will also present expert testimony and undergo cross-examination regarding rate design at the hearings. He has previously testified before the Commission. As a result of our extensive experience in presenting expert testimony before regulatory commissions, we believe that the best preparation for responding to cross-examination by others is to present and thoroughly verified pre-filed written testimony at the onset For cost of capital issues, Mr. Rothschild will be the expert witness. Mr Rothschild has not previously testified in North Dakota, but has presented expert testimony on cost of capital before a number of other state regulatory commissions.

9. We shall assist Staff subsequent to the hearing by preparing proposed findings of fact with respect to issues relevant to our scope of work.

Substantive Approach to Analysis Issues Identified in the RFP

In the following subsections of our proposal, we address our substantive approach to addressing the issues encompassed within each of the five issue groups identified in the RFP.

Approach to Revenue Requirement Analysis (Rate Base and Regulated Net Income)

We propose to review such revenue requirement issues in the following manner. Since we have not yet begun an in-depth study of the project, the following discussion consists of areas that will have to be addressed and general areas that are likely to be of concern, and our approach to them.

Revenue Requirement

We will review the Company's proposed revenue requirement, recommend adjustments, and independently develop a revenue requirement. The revenue level should be sufficient to enable the utility to recover all of its prudently incurred costs found to be includable in the adjusted test year, plus an adequate return of its capital invested in used and useful assets devoted to the provision of jurisdictional utility service. In other words, total allowed revenues should equal total operating expenses plus depreciation, and an adequate return on investment. This is, of course, inclusive of a sufficient level of income taxes to provide an opportunity to earn such return on an after-tax basis.

Test Year

Keeping in mind prior Commission orders and North Dakota law, we will review the test year used by the Company to determine its appropriateness. We will carefully analyze any adjustments proposed by the Company to the test year to ensure that there is a proper synchronization of rate base with revenue and expense levels.

Using a historical test year assumes that revenue and expense levels experienced in the past will continue in the future; this may not be the case. Unusual events, costs, and changes in operations will be evaluated for this purpose. In the event the historical test year does not facilitate the rate recognition of such items as plant being placed into service, we will maintain the test year concept of matching rate base, return, and expenses with appropriate levels of sales.

In the event that the Company has used a projected test year or a partially historic/partially projected test year, we will analyze all budgets and forecasts underlying the projected data. Such projections will be compared to historical data and all unusual increases and decreases in costs will be questioned.

Rate Base Analysis

We would expect to perform the following analysis pertaining to rate base. Due to the time and budget constraints, work in this area will be limited in scope and will commence with a review of the last rate case and historical comparisons, along with a review of NSP's filing. Variations in NSP's filing from the prior case and deviations from Commission precedent will be used as guidance for where to focus the analysis. We will focus on issues that have large dollar impacts. We do not propose to perform a cash working capital calculation.

Based on the above overall approach, issues concerning the rate base determination that may be encountered include the following:

Review the Company's accounting and budget data to ensure that the per book or forecast balances included in rate base are stated appropriately. Also ensure that all major balance sheet accounts have, in some way, been accounted for through either the rate base or capital structure ratemaking components.

Review all Company adjustments to the rate base to ensure their propriety. Rate base adjustments are normally made to update items such as plant in service to a specified date, to adjust working capital and depreciation reserve to correspond with adjusted expenses, and also to include adjustments to deferred tax offsets to the rate base. All adjustments must meet the requirements of being known and measurable. Where Company adjustments are believed to be inappropriate, we will propose alternative adjustments and explain reasons for rejecting the Company adjustment in testimony.

Analyze sources of non-investor supplied capital. Determine whether all non-investor supplied capital has either been appropriately deducted from the rate base or included in the capital structure at zero cost. Balances that should appropriately be deducted from the rate base include.

1. Accumulated deferred income taxes, reflecting the fact that this represents non-investor supplied capital.

2. Customer deposits, while at the same time treating customer deposit interest as an above-the-line expense.

3. Pre-1971 Unamortized Investment Tax Credits. Deduction from rate base of these tax credits, is not prohibited by law. To the extent that such unamortized balances are still on the Company's books, they should be deducted from rate base as non-investor supplied capital.

4. Accounts Payable associated with Plant in Service (PIS), Construction Work in Progress (CWIP), and Materials and Supplies (M&S). The PIS, CWIP, and M&S balances included in the rate base for a current return that may be partially financed by accounts payable on a continuous basis throughout the year. Such payables (e.g. contractor retentions) represent vendor-supplied capital and should be offset against the PIS, CWIP, and M&S balances in the rate base.

5. Determine whether customer advances or contributions in aid of construction are present on the Company's books and propose recommendations accordingly.

6. Review balance sheets for any other types of non-investor supplied capital, which should be reflected in the determination of rate base. These would include reserves for items such as injuries and damages, property damage, self-insurance, etc.

Determine if NSP has included any CWIP in rate base. We will determine if the expected in-service date is accurate. If CWIP is not expected to be in service within a reasonable period after the test year-end, then it should not be included in the rate base.

Review and analyze all costs associated with new plant, which goes into service during the test year. Ensure that the cost savings associated with it are simultaneously and adequately reflected.

Evaluate any Plant Held for Future Use (PHFFU) in the rate base. Some Commissions have approved the inclusion of PHFFU in the rate base. We will analyze the items requested for inclusion by the Company, verify dollar amounts, and existence of a definite plan of use within a reasonable time frame for each piece of property held for future use included in rate base This will allow us to determine whether or not each specific item merits inclusion in the rate base.

Ensure that components of the rate base are determined on a consistent basis with components of capital employed (e.g. 13 month averages, beginning and end-of-year average balances). If considered helpful to our analysis, we will reconcile the rate base with capital structure. This can be an important analytical procedure in testing the overall reasonableness of rate base.

Analyze the specifics of certain typical rate base accounts, such as prepayments and M&S, in sub-account detail, to ensure that all sub-accounts are proper for inclusion in the rate base. Items such as temporary investments, which earn their own return or non-utility items should be excluded from the rate base.

Ensure that the Company's accounting for prepayment items are proper. Investigate the interrelationship of prepaid balances with the determination of cash working capital under the lead/lag study approach to verify that no double counting is included in the rate base.

Ensure that the inclusion of deferred debits is appropriate and review deferred credits to determine if any accounts or individual sub-accounts are proper as offsets to the rate base.

Review the deferred income tax offset to the rate base in conjunction with detailed revisions of Account 190. Account 190 (accumulated deferred income tax debit) represents an increase to rate base. Therefore, it is important to ensure that each sub-account is proper for inclusion.

It appears from NSP public financial statements that the company is deferring natural gas commodity, transportation and storage costs which are greater or less than

amounts presently recovered through existing rate schedules. Consequently, NSP may have an under-recovered or over-recovered balance of deferred gas costs, which may impact the derivation of rate base. If deferred gas costs are proposed to be included in rate base by NSP, we will evaluate the balance for appropriateness, including an assessment of how financing charges related to the deferred gas cost balance are recovered in rates, and whether the balance during the test year may have been impacted by abnormal weather or includes costs which are not appropriate for ratemaking purposes. To the extent that NSP has over-recovered gas costs, the resulting balances appear to be recorded in other accrued liabilities. If over-recovered balances are consistently occurring on NSP's books, this may represent a source of capital to the company that may need to be considered as a rate base deduction

Regulated Net Income Analysis

In general, we will review operating income and expenses, including normalizing and out-of-period pro forma adjustments.

Our review of the operating income statement will include the following areas:

Revenues and Sales in the Test Year

Ensure that current revenues reflect the revenues, which should be generated based on the rates currently in effect. This will be done by verifying billing determinants to historical experience.

Analyze the Company's filing to determine if test year sales and revenues are representative of normal going-forward conditions, and propose any necessary adjustments.

Operating revenues will be analyzed to ensure that the proper levels of revenue are reflected in these accounts. Adjustments to annualize sales for year-end customer levels and usage will be appropriately coordinated with weather normalization adjustments after review

We will closely examine the impact of any large industrial or commercial customers closing operations or adding new operations in the Company's service territory.

The sales mix will be analyzed to ensure that unusual or non-recurring conditions have not temporarily caused shifts in usage between rate classes, such as residential and commercial. Any unusual shift in usage patterns can affect revenue calculations and cost allocation studies.

The components of "other revenues" will be reviewed to ensure that an appropriate level of each type has been reflected in the test year.

Determine whether appropriate projections are made for occasional gas sales revenue, and other types of miscellaneous revenue, which utilities frequently claim are difficult to accurately forecast.

Uncollectible accounts will be analyzed to ensure that the adjusted test year balance is representative of normal conditions. We will review the correlation of uncollectibles to revenues Test year uncollectibles will be compared to historical results. Additionally, we will:

1. Examine the historical results experienced by the Company in the past in order to determine whether the proposed uncollectibles rate is reasonable, and whether it will likely reflect future occurrences.

2. Examine the method the Company used to calculate uncollectibles for reasonableness and compliance with Commission policy

3. Verify the accuracy of all source amounts, including items such as gross write offs as well as residential and commercial revenues The mathematical accuracy will also be checked to ensure that the amounts are correct

4. Determine an appropriate provision for uncollectibles in conjunction with the calculation of the gross revenue conversion factor.

5. Evaluate the level of uncollectibles by computing uncollectibles-to-sales ratios, comparing to historical experience, and investigating Company collection policies and efforts.

We will review test year late payment charge revenues. This review will be coordinated with an analysis of uncollectibles.

Further review of weather on NSP's gas sales may be conducted, if deemed necessary. Such review may include the following type of analysis:

1. Evaluate weather information gathered from weather monitoring stations (airports and other weather stations) and information available from government resources

2. Determine which weather station's data should be considered representative of the Company's service territory

3. Compare data to historical averages (which represent "normal") to determine if the test year weather falls outside the range of what is considered normal.

4. Test year weather that falls significantly outside the normal range requires that test year revenues be adjusted as if the weather had been classified as "normal".

Review and analyze the Company's treatment of revenues received off system sales and net nonjurisdictional revenues. We will coordinate this review with our evaluation of the assignment/allocation of the related costs.

Operation and Maintenance Expenses

Maintenance expense will be examined to ensure that the test year does not include unusual or non-recurring maintenance, which should be amortized over a longer period for rate case purposes.

Gas costs and transmission costs. Gas cost is the largest single component of NSP's revenues, comprising about 80% of NSP's total revenues in 2001, according to the RFP. For most gas distribution utilities, gas costs are recovered through a separate rate. We will coordinate the pro forma amounts of gas costs with any revenue adjustments, including year-end annualizations and weather normalizations. To the extent deemed appropriate for this proceeding, we will also review the components of NSP's gas costs and related transportation. We have extensive experience reviewing utility gas purchasing activities and fuel procurement management We will discuss with Staff the extent to which NSP's gas purchasing, transportation and storage costs should be reviewed in conjunction with this proceeding. Depending upon Staff's guidance in this area, discovery may be utilized to obtain an understanding of NSP's gas purchasing practices, including arranging for pipeline transportation, and incurrence of related costs. In other jurisdictions, we have also seen interest expressed concerning methods by which utilities can limit their exposure to upside gas price volatility as part of their gas procurement. For purposes of determining the cost of service in the NSP rate case, the analysis of gas cost is anticipated to be limited, unless we are otherwise instructed by Staff.

The review of non-gas cost operating and maintenance expenses is anticipated to comprise a significant portion of the cost of service review for issue 3.

Review labor and fringe benefit costs for reasonableness. We will review any adjustments for increased labor costs based on projected wage increases. Wage levels of current employees will be evaluated to determine if any increases are reasonable. We will also review wage and benefit analyses conducted by or prepared for the Company. We will compare management wage increases with those granted union employees as the result of arms-length bargaining

Compare budgeted with actual wages and staffing levels for a representative historical period. Evaluate whether the Company budgets for unfilled employee positions, or if they otherwise tend to over-project budgeted wages. We will consider an adjustment for average vacancies.

Review relocation expense. Review any austerity measures, such as a temporary hiring freeze, leaving unfilled job vacancies produced by attrition, and offering voluntary early retirement. Investigate the impact upon test year employee costs of these programs. Evaluate the amortization of any large one-time costs, such as those relating to an early retirement program.

Examine the Company's accounting for pension benefits. Ensure that book pension expense is computed in accordance with FASB 87 guidelines. Determine the basis for the utility's ratemaking claim for pension expense. Consider adjustments to pension expense, in light of prior Commission decisions on this issue.

If the Company has supplemental retirement plans for officers and directors, or an Employees' Investment Plan (i.e. 401k), ensure that the costs of these plans reflected in the test year reflects a normal, reasonable level of costs.

Evaluate the Company's proposal in regard to post retirement benefits other than pensions (PBOP). The prior decisions of the Commission provide guidance for how utilities are to account for the benefits other than pensions (PBOP's) using the accrual method prescribed by SFAS 106. Moreover, the SFAS 106 accruals remain subject to Commission review of prudence and reasonableness in rate cases. In performing an investigation of PBOP accounting, we may investigate some or all of the following

1. Identify the Company's PBOP liability under SFAS 106. Review and evaluate any actuarial studies the Company or its actuary has conducted to estimate annual PBOP costs, including interest cost, service cost, and amortization of the transitional PBOP cost existing at the date the Company adopted FASB 106 for book accounting purposes.

2. Evaluate whether or not the Company's request in the current proceeding is in compliance with the Commission's prior decision.

3. Determine whether the Company has fully funded its plan under the most tax advantageous methods.

4. Review all steps being taken or planned by the Company to reduce its prospective employee benefit costs and PBOP liability.

5 Obtain the most recent actuarial estimates for the FASB 106 accrual In past cases, we have noted that utilities' initial estimates of FASB 106 accruals have been high, and more current estimates reflect reduced accrual amounts.

6. Investigate whether the utility has capitalized a portion of its FASB 106 accrual cost. In past cases, we have noted instances where utilities have failed to capitalize

portions of their FASB 106 accruals and have inappropriately attempted to over-charge O&M expense as a consequence of such failure.

Review the Company's accounting for legal expense to ensure that unusual or inappropriate costs are not charged to retail ratepayers. The test year should reflect a normal level of legal expense. Remove any penalties or unusual settlements from test year expenses, which should reflect normal operations. Consider deferral of large legal expenditures for litigation in progress concerning questionable areas, e g., lawsuits against officers and directors for alleged imprudence.

Review the impact of FASB 112 on expenses. The FASB 112 accrual is in the nature of a one-time establishment of a liability balance, with subsequent annual "incremental" adjustments. In this regard, it is similar to the compensated absence accrual established pursuant to FASB 43. It is the converse of unbilled revenue accounting, whereby many utilities credited Revenue and debited Unbilled Revenue Receivable (similar to an Account Receivable, but before the bill is issued) in adopting this aspect of accrual accounting. In each subsequent year, adjustments are made to the accounts for incremental changes in the balance of Unbilled Revenue. The Commission's prior handling of the unbilled revenue and the compensated absence accrual issues could therefore provide insight into potential arguments that could be presented concerning the FASB 112 issue. We will examine any FASB 112 accrual amounts proposed by the utility, and we will recommend appropriate ratemaking adjustments.

Review incentive compensation arrangements and special bonuses to employees and officers. Ensure that only reasonable amounts are included in the test year.

Review special "perks" available to top management, including "golden parachute" arrangements, use of Company assets for personal functions, bonus plans, supplemental pensions, incentive stock options, etc.

Review dues for membership in industry associations. Remove the lobbying and institutional advertising portion of such dues Obtain data concerning benefits of association programs to the Company. Review other membership dues for appropriateness as test year expenses.

Analyze test year advertising and marketing expenses. Determine which programs and activities benefit ratepayers and provide a recommendation based on this determination for recovery of advertising and marketing expenses.

1. Review copies of advertisements run and bill inserts sent during the test year. Review Company categorization of advertisements.

2. Review test year advertising to ensure that no advertising disallowed in the last docket has been included in the current docket.

3. Review customer surveys the Company may have.

4. Review Commission orders in recent utility cases to ascertain treatment (allowance or disallowance) of promotional activities. Use such orders as guidance for treatment of marketing programs.

Analyze operating and maintenance accounts by primary and sub-accounts to determine whether any significant increases or decreases in these accounts have occurred. Investigate and document the reasons for any significant changes in operating and maintenance expenses. Recommend adjustments for inappropriate increases and for unexplained, or unjustified cost increases.

Taxes Other than Income Taxes

Analyze other taxes by type to determine that the tax expense is related only to the test period under consideration.

Verify tax rates to current state statutes and tax assessments. Evaluate trends in property taxes and tax assessed valuation over a representative historical period. Use the most recent actual tax rates for all property.

Ensure that plant balances used in the calculation of property tax expense are appropriately synchronized with the plant balances reflected in rate base.

Investigate property tax refunds and ensure that they are properly treated for ratemaking purposes.

Analyze the rate used by the Company to determine whether the use of that rate is appropriate for state and municipal taxes.

Examine the tax rates for the major components of state and municipal taxes to ensure that there has been no decrease in state and municipal taxes, which should be reflected in the period being examined.

Below-the-Line Revenues and Expenses

Briefly analyze revenues and expenses in so-called "below-the-line" accounts. Examine these accounts with the intention of determining that these revenues and expenses are

properly excluded from the cost of service

Verify the embedded costs of debt and preferred stock to the financial statements and other supporting documents.

Determine whether the Company has sold any property during the test year or before, and realized a gain on such sales. Determine whether sold property was previously included in rate base to earn a return, or in depreciation expense or property taxes, i.e., included in rates. Consider whether any gain on the sale of such property should accrue to the benefit of the ratepayers.

Gain/Loss on Repurchase of Outstanding Debt

Some regulatory commissions have determined that it is appropriate to flow through the benefits of gains on repurchased debt to ratepayers. We will examine this issue to determine whether such treatment would be appropriate under the North Dakota regulatory framework.

If it is determined that any gains on reacquired debt should be amortized over a period of two or more years, then a determination must me made as to the proper ratemaking treatment of the amortized (credit) balance. The ratemaking treatment of such an amortized balance is the converse of the ratemaking treatment for unamortized debit balances, such as plant cancellation losses or deferred expenses.

Income Taxes

Review all tax computations in the rate filing

Determine that interest expense used in the tax computation is properly synchronized with the interest computation in cost of capital.

Determine that deferred investment tax credits are being properly amortized. Review tests of ITC amortization performed by the Company and/or its independent auditor to ensure compliance with IRC 46(f). Coordinate ITC amortization with depreciation rates adopted in this case.

Review the Company's federal tax returns for prior two years with particular emphasis on Schedule M adjustments.

Review the Company's deferred income taxes, focusing on any Company proposed normalization treatment which deviates from established Commission policy and procedures.

Address the issue of amortization of non-protected excess deferred income taxes.

Investigate the impact of the alternative minimum tax (AMT) on the Company's income tax expense for ratemaking purposes. AMT is allowed to be carried forward indefinitely as a credit against federal income taxes payable in the future (other than AMT). Ensure that savings from participation in a consolidated federal income tax return are appropriately recognized in the ratemaking process.

Depreciation and Amortization Expense

We will analyze the Company's calculation of test year depreciation expenses to ensure that it reflects the use of Commission authorized depreciation and is properly coordinated with the other aspects of the revenue requirement determination, including the balance for Accumulated Depreciation being reflected in rate base.

Ensure that the depreciable assets used in calculating the depreciation expense agree with the books and records of the Company

Ensure proper "matching" between depreciation expense reflected in adjusted net operating income and net plant amounts reflected in the rate base, paying particular attention to new additions to rate base.

Review each item being amortized as test year expense. Remove amortizations, which will be completed prior to rates set in this proceeding going into effect.

Rate Case Expenses

Review and analyze rate case expenses to be allowed for ratemaking purposes in this proceeding. Address the appropriate level of expenses as well as the appropriate amortization period, and treatment of the unamortized balance

Administrative and General Expenses

Ascertain the reasonableness of the Company's test year claims for administrative and general expenses·

1 Examine the individual items by account and sub-account detail, to determine whether such amounts properly relate to the provision of gas service to ratepayers.

2. Examine all membership association dues and the related expenses to ascertain the benefit to ratepayers.

3. Examine all adjustments made by the Company to the test year expenses for reasonableness. Where we find that such adjustments seem unreasonable and do not reflect actual past experience, we will provide alternative amounts to be included as expenses.

4. Examine all costs associated with Company sponsored programs in order to determine whether such amounts are reasonable, and whether the benefits to ratepayers are commensurate with the cost of those programs.

Rate Design

Ralph Smith will be the lead consultant and expert witness on rate design issues.

Larkin & Associates will review NSP's cost of service study ("COSS") and rate design ("RD") proposals for compliance with established COSS standards and principles, including, but not necessarily limited to, the guidance provided by the NARUC Gas Distribution Rate Design Manual and the NARUC publication, Gas Rate Design. We may also utilize public information and comparative statistics, such as industry information concerning average monthly customer charges for gas distribution utilities, as part of our review of NSP's proposals

Our suggested approach is to work closely with the Staff personnel assigned to the project and to conduct initial discovery on all apparent issues that would impact the COSS results and affect the development of proposed rates for residential and commercial customers. Issues would be prioritized by potential impact and importance using criteria such as the following:

- Estimated impact on residential and commercial rates.
- Consistency with Commission precedent/prior decisions, and historical rate design
- Importance of issue in setting precedent for future cases.
- Promotion of the wise use of energy.
- Matching of costs and revenues.
- Mitigation of impact on high winter bills for gas service
- Quantification difficulty.

Such prioritization of issues will help ensure that the efforts are concentrated on the most important issues and those having the largest impact on residential and commercial customers.

We will fully review NSP's cost of service study, proof of revenues, and proposed rate design to ensure that they are consistent with the Commission's policies and with established ratemaking principles. Initially, we will focus on the company's substantial increase to its customer charge.

We also will carefully review and evaluate other aspects of NSP's proposed tariff changes and rate design, including the cost of service bases for its changes and proposals.

Our review of NSP's COSS will encompass all issues raised in the Company's last rate case proceeding, as well as any new issues presented in the current study The focus will be on any NSP-proposed cost allocations and cost assignments that deviate from prior Commission orders or prior COSS, that would disadvantage residential and small commercial customers.

The COSS-RD analysis will also include a review and, as necessary, response to any adjustments to NSP's filed COSS and RD proposals made by industrial intevenors. It is not uncommon in a gas distribution company rate case to encounter proposals from industrial or large customer interests to allocate costs in a manner that allocates less cost to their rate classes and more to residential and small commercial classes. If any such proposals occur in the instant case, they will need to be reviewed, evaluated, and if appropriate, countered.

The rate design proposed by NSP will be reviewed, with a focus on its impact on residential and small commercial customers. NSP's proposals to increase the customer charge component of bills will be reviewed in detail, along with any cost support being relied upon. As appropriate, counter proposals will be presented. If necessary, alternative rate design will be developed and presented.

Mr. Smith, who has extensive experience with gas distribution utilities and who recently presented expert testimony on gas rate design before the Regulatory Commission of Alaska in an Enstar Gas rate case, will supervise the COSS-RD work, and will sponsor the testimony. He will be assisted in the analysis of COSS-RD issues by the Larkin & Associates regulatory analysts.

Cost of Capital

Mr. Rothschild will provide financial, economic and technical consultation and expert testimony to the PSC. This would include preparation and analysis of discovery, preparation and presentation of testimony, analysis of testimony and preparation of cross-examination, and preparation of briefs and assistance in negotiations as well as providing expert testimony in the areas of cost of capital and other financial issues

The work plan varies depending upon the needs of a particular case The following outline is generally followed:

1. Review filing and discuss overview of case with attorneys, staff and other consultants assigned to the case.
2. Prepare interrogatories.
3. Prepare preliminary schedules.
4. Review responses to interrogatories, and, if necessary prepare follow-up interrogatories or request permission to hold discussions with company witnesses.
5. Complete schedules associated with testimony.
6. If appropriate, assist in potential settlement negotiations.
7. Prepare direct testimony.
8. Write cross-examination questions to be asked to the witnesses of those other parties that have filed testimony on related subject matters.
9. Assist during cross-examination.

10 Submit to cross-examination.

We determine the cost of capital by applying the DCF method and the risk premium/CAPM method to our own broad group of gas distribution companies. When feasible, we also apply these approaches to the group of gas distribution companies presented by the Company cost of capital witness. We carefully examine the proper capital structure by examining not only the reported capital structure of the applicant company, but by also analyzing the relationship between the capital structure of the reporting company and the company's parent. Too often, the capital structure of a related subsidiary is manipulated to maximize regulated revenues rather than to optimize the overall cost of capital.

Our direct testimony includes a detailed analysis of the cost of capital testimony presented by the Company cost of capital witness.

III. MANAGEMENT SUMMARY

The management structure of our proposed project team ensures that our work effort produces a work product of the highest quality, in a timely manner and within budget. A project director and project manager will both be utilized to ensure that the objectives of the project are met in an effective manner.

The Larkin & Associates professional staff includes four CPAs with over 100 years cumulative business public accounting experience and utility related work. Our personnel our familiar with rate base, income taxes, lead/lag studies, cost of service, rate design and accounting adjustments as well as many other issues that have been contested in ratemaking proceedings. This background enables us to analyze these areas and to draw on knowledge gained through comparable studies performed in other utility cases.

Hugh Larkin, Jr., CPA, founder and senior partner of Larkin & Associates, will serve as project director. As head of the project team, Mr. Larkin will be available to provide expert testimony, if necessary; however, it is anticipated that Mr. Larkin will not be one of the expert witnesses for this proceeding. Mr. Larkin's regulatory experience includes rate cases, management audits, litigation assistance, and training seminars. As project director, Mr. Larkin will assume ultimate responsibility for the completion of the project and the quality of the resulting work product. Ultimate approval of scheduling and each work phase will be done under his supervision. Communications between Mr Larkin and the professional staff assigned to the project will be maintained on a daily basis

Helmuth W. Schultz, CPA, is a senior regulatory analyst and the firm's audit and tax partner. He has over 25 years of experience with regulatory consulting Mr. Schultz is particularly well versed in the regulatory arena and has presented testimony on several occasions, including before the North Dakota Commission. Mr. Schultz will perform analytical work on this project on an as needed basis.

Ralph C. Smith, CPA, is senior regulatory analyst with over 25 years of experience with regulatory consulting. Mr. Smith has provided testimony in numerous rate cases and other regulatory matters, including testimony before the North Dakota Commission. He will function as project manager for the overall work effort on this project and testify as an expert witness.. As project manager, he will coordinate the daily work efforts of the Larkin & Associates professional staff and subcontractors, monitor the progress of the project, and ensure that all deadlines are met. Mr. Smith will perform a substantial amount of the detailed analysis, and will also have primary responsibility for developing the spreadsheet models to state all adjustments and to provide reconciliation of revenue requirements, as adjustments are modified by various parties during the proceedings.

Donna M. DeRonne, CPA, is a senior consultant and has over 11 years of experience as a regulatory consultant. Ms. DeRonne has been a key member and presented testimony in numerous regulatory engagements involving gas, electric, and water and sewer utilities. Ms. DeRonne will perform analytical work on this project on an as needed basis

Tina Miller, and Mark Dady are staff accountants/regulatory analysts with Larkin & Associates. Each has prepared calculations, performed analyses, and prepared schedules and exhibits on several Larkin & Associates' engagements. They will be involved in the project by performing analytical work, preparing schedules and exhibits, editing written testimony, and verifying data.

Appendix I, Background and Qualifications – Resumes of Key Project Personnel, presents the professional resumes, with references, of the Larkin & Associates professional staff identified above. Mr. Rothschild's resume is provided in Appendix III.

Throughout this project, a high degree of communication will be maintained among all members of the project team, as well as PSC Staff. Communications will be facilitated by regular staff meetings, telephone conference calls, and written status reports.

IV. PRIOR EXPERIENCE

Larkin & Associates, PLLC

Larkin & Associates proposed project team is highly qualified to perform this engagement for the North Dakota Public Service Commission. Members of the Larkin & Associates project team have extensive experience providing consulting expertise in public utility regulation to regulatory agencies. Professional personnel proposed for this project have worked as consultants on numerous regulatory projects for regulatory commission staffs and intervenors.

Senior professionals at Larkin & Associates, including Mr. Smith and Mr. Schultz have presented expert written and oral testimony on behalf of the Staff on a number of occasions.

Our personnel are familiar with issues affecting the revenue requirement of public utilities, including the appropriateness of the test year; the determination of the appropriate capital structure and embedded costs of debt and preferred stock (we generally do not address the determination of the fair return on common equity), the overall return on rate base, rate base including working capital allowances, pro forma and known-change adjustments (e.g., for recently completed plant); net operating income including the reasonableness of test year revenues and expenses and pro forma or known-change adjustments thereto, attrition adjustments, recovery of conservation load management, and energy purchase/interconnection expenses, depreciation, operating expenses, accounting for FAS 112, taxes (both income and other); revenue requirement calculation including the gross revenue conversion factor, and other general issues, such as the measurement of management efficiency, fuel and purchased power costs, use of cogeneration and independent power production in generation planning; use of "bank balance" accounting for energy transactions with independent producers; changes to Rules and Regulations; and issues surrounding incentive regulation proposals and alternatives to rate of return regulation; as well as many other issues that have been addressed in ratemaking proceedings.

Their resumes and the qualifications of other Larkin & Associates professionals available to work on this project are presented in Appendix I.

Appendix II, Gas Case Summaries, presents a listing of natural gas regulatory engagements which qualify Larkin & Associates to undertake the work discussed herein. References are provided for each engagement, and key project team members are identified.

Subcontractor- Aaron Rothschild of Financial Consulting

Rothschild Financial Consulting is a firm specializing in utility regulation. Aaron Rothschild has worked in utility regulation for approximately six years This includes over two years experience with Rothschild Financial Consulting and four years in business planning with WorldCom both in Chicago and in several locations in Asia Additional details of RFC qualifications are presented in Appendix IV. If the project team is selected to address cost of capital issues, Aaron Rothschild, an individual subcontractor to Larkin & Associates on this project, would function as the lead consultant and expert witness in this area.

Mr. Rothschild has previously filed testimony in several other regulatory proceedings before other state commissions. His qualifications are attached as Appendix III.

V. REFERENCES

Below are three references that demonstrate our capability to perform the work for this project These references are for services on projects that are similar in nature, size and scope of work and are for regulated utility ratemaking and accounting services within the past five years. Each reference is willing to discuss Larkin & Associates performance with a North Dakota PSC representative.

Reference 1:

Client Name:	State of Connecticut Office of Consumer Counsel
Contact:	Richard Sobolewski
Address:	10 Franklin Square
	New Britain, Connecticut 06051-2644
Telephone No.:	(860) 827-2900

Reference 2:

Client Name:	Utah Committee of Consumer Services
Contact:	Dan Gimble
Address	Heber M. Wells Building, Room 408
	PO Box 146782
	Salt Lake City, UT 84114-6782
Telephone No.:	(801) 530-6674

Reference 3:

Client Name:	Florida Office of Public Counsel
Contact.	Rick Mann/Steve Burgess
Address:	111 West Madison Street
	Room 812
	Tallahassee, FL 32399-1400
Telephone No.:	(850) 488-9330

VI. COST AND PRICE

In order to best match the project effort to the Commission Staff's needs and budget, we are proposing a number of price/issue coverage combinations, as detailed below:

Larkin & Associates, Rate Base Separately
If selected only to perform work related to rate base, Larkin & Associates proposes a total not-to-exceed price of $15,000. This includes estimated professional fees of $13,500 and $1,500 for expenses. This does not include cost for an on-site review at NSP's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Regulated Net Income Separately
If selected only to perform work related to regulated net income, Larkin & Associates proposes a total not-to-exceed price of $21,000. This includes estimated professional fees of $19,500 and $1,500 for expenses. This does not include cost for an on-site review at NSP's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Combined Rate Base and Net Operating Income
We believe there would be substantial synergies in having the same consultant and witness address both rate base and net operating income issues Accordingly, if selected to perform work on issues relating to rate base and net operating income, Larkin & Associates proposes a total not-to-exceed price of $27,500. This includes estimated professional fees of $26,000 and $1,500 for expenses. This does not include cost for an on-site review at NSP's offices, which if desired by Staff, we have separately priced, as described below.

Larkin & Associates, Rate Design Separately
If selected only to perform work related to rate design, Larkin & Associates proposes a total not-to-exceed price of $9,000. This does not include cost for an on-site review at NSP's offices, which if desired by Staff, we have separately priced, as described below

Larkin & Associates, Rate Base/Regulated Net Income/Rate Design Combined
We believe there would be additional substantial synergies in having the same consultant and witness who is addressing both rate base and net operating income issues also address and present testimony on rate design. Accordingly, if selected to perform the work described in our proposal for combined issues rate base, net operating income, and rate base, Larkin & Associates proposes a total not-to-exceed price of $34,500. This includes estimated professional fees of $33,000 and $1,500 for expenses. This does not include cost for an on-site review at NSP's offices, which if desired by Staff, we have separately priced, as described below.

Aaron Rothschild, Cost of Capital

The separate issue price for the cost of capital section of this project is $15,000. This price includes $1,000 for travel and expenses, and is a firm, not-to-exceed price.

Total Project Price, All Five Issue Areas Combined

Because the members of our project team have worked together on other regulatory projects, and from past experience there may be a reasonable expectation that some issues being addressed by the project team would be settled prior to hearings, we believe there are additional opportunities for cost savings by having our proposed project team perform the work for Staff on all issue areas. If selected to perform all such work described in our proposal, our project team proposes to perform such work for a combined total not-to-exceed price of $49,500. This includes professional fees and expenses, but does not include cost for an on-site review at NSP's offices.

Estimated Additional Cost for On-Site Review at NSP Offices

In the event that an on-site review at NSP's offices is deemed necessary or desirable by Staff, our total bid would increase by $3,500. This additional amount includes professional fees plus travel expenses related to such on-site review

VII. CONFLICT OF INTEREST DISCLAIMER

The undersigned does hereby certify there is no financial substantive interest in the utilities which are or may be parties in this proceeding. It is also certified than no business officer, partner, employee, agent, or any immediate family member has a substantive financial interest in the utilities, which are or may be parties in this proceeding It is further certified that, should such a financial interest occur during the period of active involvement in the proceedings, the Commission will be immediately notified and shall have the right to terminate the contract.

Hugh Larkin Jr — 12/3/04

Hugh Larkin, Jr. — Date

**This conflict of interest disclaimer is applicable to Larkin & Associates, and Mr Rothschild.

VIII. COMPLIANCE WITH APPLICABLE LAWS & REGULATIONS

Larkin & Associates, along with Mr. Rothschild, agree to comply with all applicable Equal Employment Opportunity laws and regulations, as well as the applicable provisions of the American Disabilities Act of 1991.

APPENDIX I

BACKGROUND & QUALIFICATIONS - RESUMES OF KEY PROJECT PERSONNEL

The personnel Larkin & Associates proposes for this project are ideally suited to the project's requirements. The project team includes professionals with educational backgrounds in accounting, finance, economics, business management, taxation, law and computers as well as expertise in addressing regulatory issues for electric, gas, telecommunications, water and sewer utilities.

Members of this team have extensive experience providing consulting to regulatory agencies concerning a wide range of issues affecting public utilities. The professionals proposed for this project have worked as consultants on numerous projects for regulatory commission staffs and intervenors, and have provided litigation assistance on behalf of law firms representing utilities and others. Our team includes expert consultants and CPAs who are thoroughly familiar with the issues in utility regulatory consulting engagements.

Concise resumes emphasizing gas utility experience for the professionals proposed for this project are as follows:

Page

HUGH LARKIN, JR., CPA 1

HELMUTH W. SCHULTZ, III, CPA 5

RALPH C. SMITH, CPA 9

DONNA M. DERONNE, CPA 13

TINA MILLER 18

MARK S. DADY 21

HUGH LARKIN, JR., CPA

Mr Larkin is a certified public accountant, founder and senior partner of Larkin & Associates. He is thoroughly versed in independent auditing, as well as the design and review of accounting systems and the presentation of data for management and financial reporting. Mr Larkin is licensed in the states of Michigan and Florida.

For 30 years, Mr Larkin has concentrated in the field of public utility regulation. He has served as project leader for numerous financial and compliance audits and regulatory consulting engagements, and has testified as an expert witness on issues dealing with public utility management and regulation in over 300 proceedings His testimony has been sponsored by public utility/service commission staffs, state attorneys general, groups of municipalities, a district attorney, people's counsel, public counsel, and other such entities Jurisdictions in which Mr Larkin has presented expert testimony include: Alabama, Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kentucky, Kansas, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Vermont, Utah, Washington, Wisconsin, West Virginia, FERC and Canada

Relevant Regulatory Experience
Following are examples of gas regulatory cases in which Mr. Larkin has participated.

- Project Member in the review of the application for an increase in rates and charges filed by Questar Gas Company. Issues addressed I testimony included. Appropriate test year, revenues, declining customer usage, contributions in aid of construction, gain on sale of property, corporate cost allocations, employee levels, charges from and relationship with unregulated affiliate, incentive compensation, uncollectibles, various expense items, rate of return adjustment from affiliates, and tax credits

- Project Leader in the review of Questar Gas Company's application for an increase in rates and charges Issues analyzed and included in testimony presented by Mr Larkin included revenues, gain on sale of property, advertising expense, incentive compensation, uncollectibles, phantom stock correction, rate of return adjustment from affiliates and contingent liabilities. The revenue requirement portion of the case was settled prior to hearings

- Project Manager in the review of Connecticut Natural Gas Company's proposed performance based ratemaking plan Our testimony addressed numerous deficiencies with the Company's proposed plan Other issues addressed in testimony included· the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration

- Key project team member in the review of Southern Connecticut Gas Company's proposed performance based ratemaking plan Larkin & Associates' testimony pointed out numerous problems with the Company's proposed plan as well a discussion of the following issues· the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal Mr Larkin & Ms DeRonne also proposed an alternative performance based ratemaking plan for consideration

- Key project team member in the review of Connecticut Natural Gas Corporation's rate case filing. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Ultimately, the Company's rates were reduced. Issues addressed in

testimony included. injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense

- Project Director in the Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation. The project involved analyzing the combined utilities compliance with market power safeguards adopted in the Commissions Decision D.98-03-073 to ensure open and nondiscriminatory service was conducted. An extensive investigation of the combined utilities gas system, tariffs, contracts, and operations was conducted. The review also consisted of interviewing approximately 97 Company personnel, and reviewing over 4,000 recorded telephone calls A final report was issued that discussed the Companies' compliance with the 25 Remedial Measures and market power safeguards

- Mr Larkin was a key participant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase Testimony addressed the following issues revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

- Project Director in the review of the rate increase request of the Connecticut Natural Gas Corporation Issues addressed in Mr Larkin's testimony included· plant additions, accumulated depreciation, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution, rent expense, payroll, employee benefits, matching gift program, personal use of Company automobile, directors' and officers' liability insurance, outside services, rate case expense, economic development expense, uncollectibles, lobbying expense, membership dues, miscellaneous expenses, general inflation adjustment, depreciation expense, property taxes, income tax expense, and interest synchronization

- Project Director in the review of the application for an increase in rates and charges filed by the Mountain Fuel Supply Company Testimony addressed the Company-proclaimed impact on its working gas inventory and labor requirements resulting from FERC Order 636 Another issue of paramount importance was unbilled revenue. Other issues included: cash working capital, accumulated deferred income taxes, "banked" vacation, equal payment plan, payroll expense, overtime expense, stock purchase plan expense, O&M expense percentage, payroll taxes, executive incentive retirement plan, supplemental executive retirement plan, postretirement benefits other than pensions, and consolidated income taxes

- Project Director in the review of the request of the Indiana Gas Company to increase its rates Issues addressed in Mr. Larkin's testimony included weather normalized gas sales, appropriate ratemaking treatment of an acquisition adjustment, inter-company allocations, collection charge revenues and changes in customer levels

- Project Director in the review of the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates included: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue,

payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes

- Project Director in the review of Southern Union Gas Company's request for an increase in rates Issues included: acquisition adjustment amortization, investment tax credit amortization, liability insurance expense, and acquisition investigation costs

- Project Director in the audit and review of United Cities Gas Company's rate increase request Policy issues addressed in Mr Larkin's testimony included. ratemaking treatment of acquisition adjustment, non-compete agreement, pipeline safety deferrals, gas costs, employee benefits and distribution expense

- Project team member in the review of a rate increase request by Hope Gas, Inc The case was settled prior to hearings. Issues specifically addressed by Larkin & Associates included· post-test year plant additions, consolidated tax savings, revenues, labor costs, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expense

- Project Director in the review of accounting and revenue requirement issues of the Southwest Gas Corporation. Specific issues included prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposition of property and officers' compensation

- Project Director in the review of Southwest Gas Corporation's Purchased Gas Adjustment Report The following topics were addressed: lost and unaccounted for gas, adjustment to account 191 for tier-2 gas cost corrections, Santa Fe margin on system gas sales to be credited to ratepayers, allocation to Arizona of Santa Fe's profits on end-user sales

- Project Director in the review of Mountaineer Gas Company's request for an increase in rates Issues included plant in service, accumulated depreciation, sale of liquid propane gas plant, plant acquisition from Columbia, materials and supplies inventory, prepayments, working cash allowance, customer deposits, accrued vacation pay, rate refunds, unclaimed accounts, weather normalization, commercial and industrial sales growth, miscellaneous revenue, O&M expense, payroll expense, pension expense, uncollectibles, rate year expense, expense for mandatory drug/alcohol testing, legal and outside services expense, affiliated transactions, rate case expense, truck lease expense, inflation adjustment, EDP lease expense, advertising expense, software expense, taxes other than income, payroll taxes and income taxes

- Project Director in the evaluation of the impact of the Tax Reform Act of 1986 on the gas distribution utility operations of the Northern States Power Company Issues included reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA associated impacts upon utility rates.

- Project Director in the analysis of the Connecticut Natural Gas Corporation to determine the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impacts of the Tax Reform Act on the cost of service and revenue requirements. Other areas examined were· unbilled revenues, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to CNG's calculations.

- Project Director in the review of Southwest Gas Corporation's Audit of Gas Procurement Practices and Purchased Gas Costs The following topics were addressed· summary of audit conclusions and recommendations, propriety of deferred gas account, accrual of PGA reports,

take-or-pay, two-tiered gas costs, non-traditional gas purchases from affiliate, ratemaking implications of SWG/Santa Fe/NGC relationship and acronyms and definitions

- Project Director hired to research and describe in detail the historical development of natural gas transportation issues at Federal and State jurisdictional levels in the case of Reynolds Metals Company vs The Columbia Gas System, Inc In addition, the calculation of damages and present alternative damage calculations

A complete list of cases in which Mr Larkin has participated/testified will be provided upon request

Previous Positions

- Employed by the international certified public accounting firm Peat, Marwick, Mitchell and Company from 1963 through 1969. Supervised major audits of the Detroit office.
- Partner in the public accounting firm of Tischler & Lipson, 1969-1970.
- Formed the certified public accounting firm of Larkin, Chapski & Company in 1970 (reorganized in 1982 as Larkin & Associates)

Education

- Bachelor of Science, Accounting, Michigan State University, East Lansing, Michigan, 1960.
- Certified Public Accountant, 1966.
- Continuing professional education necessary to maintain CPA license

Professional Affiliations

- Michigan Association of Certified Public Accountants
- American Institute of Certified Public Accountants

References

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- Richard Sobolewski
  State of Connecticut
  Office of Consumer Counsel
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  New Britain, Connecticut 06051
  (860) 827-2900

- George Fleming, Esq.
  Mississippi Public Service Commission
  Walter Sillers State Office Building
  P O Box 1174
  Jackson, Mississippi 39215-1174
  (604) 961-5400

HELMUTH W. SCHULTZ, III, CPA

Helmuth ("Bill") Schultz, a certified public accountant and management consultant, was employed with Larkin & Associates' predecessor firm, Larkin, Chapski & Company, in 1975 He is presently a Larkin & Associates partner and, as such, is responsible for all the accounting and much of the auditing work done by the firm. Mr Schultz has evaluated numerous issues affecting regulated public utilities including capital structure, rate base, sales, fuel and purchased power expenses, O&M expenses, taxes of all types, and management controls over operations and expenses. He has made projections in the areas of sales, required generation, capital structure, rate base, overhead, O&M expenses, taxes, and cost of debt. Mr Schultz has testified as an expert witness in numerous regulatory proceedings

Relevant Regulatory Experience
Following are examples of gas regulatory cases in which Mr Schultz has participated.

- Project Member in the review of Peoples Gas System's request for an increase in rates Our testimony addressed projected additions to plant in service, construction work in progress, off-system sales; charges from and contract with affiliated sales and marketing entity, separation of employees into non-regulated sales and marketing entity, charges from parent company and affiliates; promotional programs, advertising expense, employee levels, incentive compensation; employee benefits, trending adjustments, and impact of Economic Stimulus Package signed into law on March 9, 2002 on deferred income taxes

- Project Member in the review of Yankee Gas Services Company's application for an increase in rates Mr. Schultz analyzed issues including rate base, system expansion project, working capital, regulatory pension liability, SERP, payroll expense, incentive compensation, payroll-related expenses, benefit expense, and uncollectible and hardship forgiveness/matching payment plan expenses

- Project team member in the review of Southwest Gas Corporation's application to amend its rate schedules The following issues were addressed rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc Adjustments to operating income included labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs

- Project team member in the review of Southern Connecticut Gas Company's rate case filing Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Issues addressed in our testimony included conservation expenditures, working capital, payroll, incentive compensation, pensions, PBOP, early retirement plan expense, outside services, computer system maintenance expense, age change program cost savings, uncollectibles, environmental remediation amortization; property taxes, reduction of income tax reserve, and federal income taxes

- Project Member Larkin & Associates was contracted to conduct a financial review of Southern Connecticut Gas Company Larkin & Associates recommended adjustments to both rate base and operating income. An alternative ratemaking plan and performance based ratemaking plan were both further examined Specific areas analyzed and addressed truckline project, conservation expenditures; working capital, incentive pay; payroll, payroll tax expense; pensions, health care benefits and other benefits; early retirement plan expense, outside services expense, computer system maintenance expense, AGA dues expense; age change program cost savings, additional cost savings; amortization of environmental remediation costs, amortization of three-

way payment forgiveness plan; uncollectibles, lease income, property tax expense, reduction of income tax reserve, income tax expense; and interest synchronization.

- Mr Schultz was a lead consultant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request. Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase Testimony addressed the following issues revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company Consequently, corporate allocations were of particular concern in this case.

- Project team member in the review of Connecticut Natural Gas Corporation's rate case filing Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Ultimately, the Company's rates were reduced. Issues addressed by Larkin & Associates in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

- Lead Consultant Assisted the Office of Consumer Counsel of the State of Connecticut in a financial review of Southern Connecticut Gas Company. The review determined that the Company was over-earning and a reduction in rates was recommended As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control Mr Schultz testified as an expert witness in this case Issues addressed by us in our testimony included plant-in-service, conservation expenditures, working capital, inflation, payroll, incentive compensation, pensions, PBOP, outside services, advertising, rent expense, leak survey costs, uncollectibles, Conservation Adjustment Mechanism, depreciation, amortization; property taxes, reduction in state income tax rate, federal income taxes, and cost savings from sale and lease back of liquidated natural gas facility

- Project Manager in the review of the rate increase request by Connecticut Natural Gas Corporation. Issues addressed included. plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization.

- Lead Consultant retained to review the filing of the Minnesota Alliance for Fair Competition (MAC) against Minnegasco and to analyze the July 1993 filing by Minnegasco in response to MAC's filing Mr Schultz was to analyze the filings and make a determination as to whether Minnegasco's Cost Apportionment Manual provide a means of· 1) determining whether costs can be identified, 2) determining if an allocation process is reasonable such that all direct costs are allocated, the remaining common costs to be allocated are reasonable, and the allocator being used is reasonable, 3) determining if the allocation process is auditable, and 4) determining if an audit trail exists

- Key project team member in the review of the accounting and revenue requirements of Southwest Gas Corporation Prefiled testimony addressed the following issues· prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposal of property and officers' compensation.

- Project Manager in the review of the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates included· natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

- Key project team member in the review of Southwest Gas Corporation's - Purchased Gas Adjustment Report The following topics were addressed lost and unaccounted for gas, adjustment to account 191 for Tier-2 gas cost corrections, Santa Fe margin on System Gas sales to be credited to ratepayers, allocation to Arizona of Santa Fe's profits on end-user sales.

- Project Manager Larkin & Associates was retained by the Iowa Utilities Board to perform an audit of Peoples Natural Gas Company's direct assignment and allocation of costs to its non-regulated operations in the State of Iowa. The purpose of our audit was to assess if the Company complied with its Cost Allocation Manual and to evaluate the propriety of the allocation methods embodied within the Manual

- Project Manager in the determination of the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impact of the Tax Reform Act on the cost of service and revenue requirements Further, examine unbilled revenue, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to Connecticut Natural Gas' calculations

- Key project team member in the audit of gas procurement practices and purchased gas costs of Southwest Gas Corporation The following topics were addressed. summary of deferred gas account, accuracy of PGA reports, take-or-pay, two-tiered gas costs, non-traditional gas purchases from affiliate, ratemaking implications of SWG/Santa Fe/NGC relationship and acronyms and definitions

- Lead Consultant retained by the Delaware Valley Chapter PCAUUP to review the accounting records of Philadelphia Electric Company's gas operations with specific focus on the Gas House Heating Service Contract Program The purpose of the review was to attempt to determine the propriety of the Company's recording of revenue and expenses for the Contract Service Program In addition, attempted to determine whether the Contract Service Program was subsidized by ratepayers' monies and whether the price of the program was below an average variable cost

A complete list of cases in which Mr. Schultz has participated/testified will be provided upon request

Education

- Bachelor of Science in Accounting, Ferris State College, 1975
- Certified Public Accounting Certificate, 1980
- Continuing education required to maintain CPA license

Professional Affiliations

- Michigan Association of Certified Public Accountants

References

- Geoff Commons, Esq.
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  112 State Street
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  (802) 828-2811

- Richard Sobolewski
  State of Connecticut
  Office of Consumer Counsel
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  (860) 827-2900

- Mike Diller
  North Dakota Public Service Commission
  12th Floor, State Capital
  Bismarck, ND 58505
  (701) 328-2400

RALPH C. SMITH, CPA

Mr Smith's professional credentials include being a Certified Financial Planner™ professional, a certified rate of return analyst, a licensed certified public accountant and attorney He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, Ohio, Pennsylvania, South Carolina, Texas, Washington, Canada, Federal Energy Regulatory Commission and various state and federal courts of law He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions

Relevant Regulatory Experience
Following are examples of gas regulatory cases in which Mr Smith has participated

- Project Manager Larkin & Associates was retained by the New Jersey Department of Law and Public Safety to assist in submitting comments to the Environmental Protection Agency regarding the EPA's proposed rule published on December 31, 2002 at 67 Federal Register 80290 entitled, "Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR) Routine Maintenance, Repair and Replacement "Larkin & Associates assisted the NJ Department of Law with research and drafting of the comments submitted to the EPA

- Project Manager in the review of Southwest Gas Corporation before the Arizona Corporation Commission Involvement included, but was not limited to, preparing testimony, performing data analysis and monitoring the progress of the overall project. Mr Smith was also actively involved with the Southwest Gas Corporation's Rebuttal & PGA Audit as well as the Audit of Gas Procurement Practices and Purchased Gas Cost both before the Arizona Corporation Commission.

- Project Manager in the Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation. The project involved analyzing the combined utilities compliance with market power safeguards adopted in the Commissions Decision D.98-03-073 to ensure open and nondiscriminatory service was conducted Mr Smith performed an extensive investigation of the combined utilities gas system, tariffs, contracts, and operations The review also consisted of interviewing approximately 97 Company personnel, and reviewing over 4,000 recorded telephone calls. A final report was issued that discussed the Companies' compliance with the 25 Remedial Measures and market power safeguards

- Project team member in the review of Southern Union Gas Company's revenue requirements Mr Smith filed testimony addressing issues resulting from this review Issues included Acquisition adjustment amortization, investment tax credit amortization, liability insurance expense and acquisition investigation costs

- Project Manager in the analysis of Equitable Gas Company's rate base, operating income and revenue requirement issues including the Company's capitalization of promotional allowances, projected plant additions, accumulated deprecation, materials and supplies, accounts payable related to CWIP, customer deposits, provision for rate refund, cash working capital (billing lag, collection lag, other taxes lag, income tax lag, interest expense lag) residential sales, take-or-pay liability amortization, uncollectibles, advertising and promotional expense, recoveries of theft gas,

associated dues, employee retirements, projection of work force, pension expense, marketing study, energy assistance program, depreciation, gross receipts tax, customer deposits interest and income tax expense.

- Project Manager in the evaluation of Southwest Gas Corporation. Reviewed gas procurement practices and purchased gas costs Retained by Arizona Corporation Commission to prepare a report on audit of gas procurement practices and purchased gas costs The following topics were addressed: Summary of Audit Conclusions and Recommendations; Propriety of Deferred Gas Account, Accuracy of PGA Reports; Take-or-pay; Two-Tiered Gas Costs; Non-Traditional Gas Purchases from affiliate, and Ratemaking implications of SWG/Santa Fe/NGC Relationship

- Project Manager in Larkin & Associates' review of Citizens Utilities Company, Arizona Gas Division's request for an increase in rates. Responsible for analyzing rate base and net operating income issues, quantifying adjustments, and writing testimony Specific issues addressed included Stamford Administrative Office common plant balance, cash working capital, revenue annualization, payroll expense, employee benefits expense, and investment tax credit amortization

- Project manager in the review of Missouri Gas Energy's ("MGE") affiliated transactions and Southern Union Company's corporate costs This was the first rate case review after the acquisition by Southern Union of MGE. MGE and Southern Union's previously owned gas distribution operations (located in Texas) were approximately the same size in terms of annual revenues and rate base This project involved a thorough review of the corporate cost allocation model that was developed after the merger occurred. Testimony addressed the following issues common plant - Austin, Texas office, accumulated deferred income taxes, corporate allocations, New York Stock Exchange listing fees (initial and ongoing) for the new company, executive stock options and stock-based compensation; SFAS 123, incentive compensation; pensions and SFAS 106 nonpension post retirement benefits, budgeting of corporate costs and employee levels, executive offices in New York City, treatment of salary expense for geographically removed executives, affiliated transactions, KellAir, an affiliated supplier of airplane passenger service, allocation factors, use of time reporting for corporate executives

- Project team member in the evaluation of the impact of the Tax Reform Act of 1986 on the gas distribution utility operations of the Northern States Power Company Issues included reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA associated impacts upon utility rates

- Project Manager Larkin & Associates was employed by the Office of Consumers' Counsel of Ohio ("OCC") to review and evaluate the material filed by the River Gas Company and the East Ohio Gas Company, the PUCO Staff, and any other parties to the proceedings, relating to FAS 106 and FAS 112. Review included, but was not limited to, Company testimony and standard filing requirements, responses to discovery, Company workpapers, the Staff Report, Staff workpapers, actuarial studies supporting the accrual of postretirement benefits and the comments and findings in prior cases. This case was settled

- Project manager in the review of the rate increase requested by CNG Transmission Corporation Issues addressed in testimony included: ratemaking treatment of extraordinary gas loss at CNG Transmission Corporation, treatment of costs incurred by CNGT associated with the Company's violations of environmental laws, and, the amortization period to be applied to CNGT's FAS 106 regulatory asset

- Project manager Larkin & Associates was hired by the Pennsylvania OCA to review Columbia Gas Company's request to increase its rates Mr Smith prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site at their Columbus, Ohio office, quantified adjustments for a wide range of issues, and prepared a report containing

the impacts of our adjustments. Larkin & Associates also quantified various alternatives as part of the "collaborative" negotiating process that resulted in the final agreement concerning the amount of rate increase

- Project Manager in the analysis of Pacific Gas & Electric Company. Issued addressed included Review revenues, sales and customer forecast, O&M expense, labor and non-labor cost, income taxes, other taxes, depreciation, return and rate base items. Adjustments were proposed for rad waste disposal expense, non-routine maintenance expense, Geyers effluent pipeline project, outage management system, integrated distribution information system, distribution expense - tree trimming, customer accounts expense, customer charge, relocation expense, long-term disability expense (FAS 112), Performance Incentive Plan, total compensation, hazardous substance tax expense, nuclear decommissioning expense, depreciation on hydraulic production plant, and 215/245 Market Street headquarters building seismic retrofit project costs

A complete list of cases in which Mr Smith has participated/testified in will be provided upon request.

Previous Positions

With Larkin, Chapski & Co , the predecessor firm to Larkin & Associates, Mr Smith was involved in utility regulatory consulting, tax planning and research for businesses and individuals, tax return preparation and review, independent auditing, review and preparation of financial statements Installed computerized accounting system for a realty management firm.

Education

- Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.
- Master of Science in Taxation, Walsh College, Michigan, 1981 Master's thesis dealt with investment tax credit and property tax on various assets.
- Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.
- Continuing education required to maintain CPA license and CFP certificate
- Received CPA certificate in 1981 and certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Professional Affiliations

- Michigan Association of Certified Public Accountants, Committee on Management Consulting Services
- Michigan Bar Association
- American Bar Association, sections on public utility law and taxation

References

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  Residential Utility Consumers Office
  1110 W Washington, Ste 220
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- John Wallace, Manager, Revenue Requirements Analysis
  (602) 542-0865
  Janice Alward, Attorney
  (602) 542-6029
  Christopher Kempley, Attorney
  (602) 542-6025
  Arizona Corporation Commission
  1200 West Washington
  Phoenix, Arizona 85007

- Sam DeFrawi
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  Building 212, 4th Floor
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  (202) 685-0130

DONNA M. DeRONNE, CPA

As a certified public accountant with Larkin & Associates, duties include the analysis of utility rate cases, researching accounting and regulatory developments, preparing computer models and spreadsheets, and preparation of written testimony and exhibits Ms DeRonne has testified as an expert witness in numerous regulatory proceedings Jurisdictions in which Ms. DeRonne has participated in the analysis of regulatory filings include Alaska, Arizona, California, Connecticut, Florida, Guam, Hawaii, Illinois, Indiana, Kentucky, Pennsylvania, Rhode Island, Utah, Vermont, Virginia, Washington, West Virginia and Wisconsin

Relevant Regulatory Experience
Following are examples of gas regulatory cases in which Ms DeRonne has participated

- Project Manager in the review of Peoples Gas System's request for an increase in rates. Our testimony addressed projected additions to plant in service, construction work in progress, off-system sales, charges from and contract with affiliated sales and marketing entity, separation of employees into non-regulated sales and marketing entity; charges from parent company and affiliates; promotional programs, advertising expense, employee levels, incentive compensation; employee benefits, trending adjustments, and impact of Economic Stimulus Package signed into law on March 9, 2002 on deferred income taxes

- Project Manager in the review of the application for an increase in rates and charges filed by Questar Gas Company Our testimony addressed the following issues· Appropriate test year, revenues, declining customer usage, contributions in aid of construction, gain on sale of property, corporate cost allocations, employee levels, charges from and relationship with unregulated affiliate, incentive compensation, uncollectibles, various expense items, rate of return adjustment from affiliates, and tax credits

- Project Manager in the review of Southwest Gas Corporation's application to amend its rate schedules. Ms DeRonne submitted testimony which addressed the following issues rate base, work management system, post-test year safety additions, completed construction not classified correction, cash working capital, corrections to prepayments, working capital offset for payments from UPI, and the relationship between Southwest Gas and Utility Partners Inc Adjustments to operating income included. labor annualization, management incentive plan, outside contractor expense, office closures, expired amortizations, amortizations of payments from UPI, environmental amortizations, American Gas Association membership dues, officer retreat expense, directors' and officers' liability insurance, property tax expense, interest synchronization, and merger related costs

- Project Manager in the review of Yankee Gas Services Company's application for an increase in rates. Ms DeRonne addressed issues and filed testimony in this case regarding rate base, system expansion project, merger synergies and related adjustments, fuel diversity fund, marketing expense, inflation adjustment, AGA dues expense, environmental remediation costs, gain on sale of property, property tax refund, property tax expense, and income tax expense. Ms DeRonne also prepared and sponsored the overall revenue requirement schedules on behalf of the Office of Consumer Counsel

- Project Member in the review of PG&E's application for a rate increase, including its testimony, exhibits and workpapers Testimony was filed by Larkin & Associates on behalf of the Navy representing the Department of Defense and all other Federal Executive Agencies (Navy) to address the various issues. Those issues included GRC Policy, Electric Revenues at Present Rates, Electric Generation Expenses, Gas Revenues at Present Rates, Other Operating Revenues, Total Compensation Expense, Administrative & General Expenses, Injuries and Damages (Account 925), Pensions and Benefits (Account 926), Long-term Disability/FAS Expense, Meter Reading, Payroll Taxes, Diablo Canyon Decommissioning, Humboldt

Decommissioning, Fossil and GeoThermal Decommissioning, and the ORA's Results of Examination.

- Project Manager in the review of Southern Connecticut Gas Company's rate case filing Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Issues addressed in testimony included. conservation expenditures, working capital; payroll; incentive compensation; pensions; PBOP; early retirement plan expense, outside services; computer system maintenance expense, age change program cost savings, uncollectibles, environmental remediation amortization, property taxes, reduction of income tax reserve; and federal income taxes.

- Project Member in the review of Questar Gas Company's application for an increase in rates and charges. Ms DeRonne evaluated revenues, gain on sale of property, advertising expense, incentive compensation, uncollectibles, phantom stock correction, rate of return adjustment from affiliates and contingent liabilities The revenue requirement portion of the case was settled prior to hearings

- Project Manager in the review of Southern Connecticut Gas Company's proposed performance based ratemaking plan. Larkin & Associates' testimony pointed out numerous problems with the Company's proposed plan as well a discussion of the following issues. the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal Mr Larkin & Ms DeRonne also proposed an alternative performance based ratemaking plan for consideration

- Project team member in the review of Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan. Other issues addressed in testimony included. the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal Mr Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration

- Key project team member in the review of Connecticut Natural Gas Corporation's rate case filing Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Ultimately, the Company's rates were reduced Issues addressed in testimony included injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.

- Ms DeRonne was a lead consultant in the review of Black Mountain Gas Division of Northern States Power Company, Page Operation's rate increase request Larkin & Associates was retained by the Residential Utility Consumer Office of Arizona to submit testimony regarding Black Mountain Gas Division of Northern States Power Company, Page Operation's request for rate increase Testimony addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company Consequently, corporate allocations were of particular concern in this case.

- Project Member in the review of the merger of CTG Resources, Inc and Energy East Corporation. Ms DeRonne evaluated certain merger issues including the merger's effect on competition in the State of Connecticut, the merger's consistency with public interest; whether it would benefit both consumers and stockholders, whether there were acceptable customer protections in place to ensure effective cost control; how the merger would effect regulation; and whether there were any factors benefiting customers which clearly compel the approval of the merger.

- Project Member in the review of the merger application between Energy East and Connecticut Energy Corporation. Ms. DeRonne evaluated the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control.

- Project Manager Assisted the Office of Consumer Counsel of the State of Connecticut in a financial review of Southern Connecticut Gas Company The review determined that the Company was over-earning and a reduction in rates was recommended. As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control. Ms DeRonne testified as an expert witness in this case. Issues addressed in testimony included: plant-in-service, conservation expenditures, working capital; inflation, payroll, incentive compensation, pensions, PBOP, outside services, advertising; rent expense, leak survey costs, uncollectibles, Conservation Adjustment Mechanism; depreciation, amortization, property taxes, reduction in state income tax rate; federal income taxes, and cost savings from sale and lease back of liquidated natural gas facility

- Key project team member in the review of Connecticut Natural Gas Company's rate filing Assisted with the preparation of data requests, analysis of data, on-site review, and preparing testimony, schedules and exhibits Ms. DeRonne also testified as an expert witness in this case Issues of this case were Natural gas vehicles, software additions, working capital - O&M, accounts payable related to gas materials and supplied, non-gas materials and supplies, deferred credits, deferred conservation expense, economic development assistance deferred debits, sales, late payment revenue, payroll, pensions, employee benefits, personal use of company vehicles, uncollectibles, hardship arrearage forgiveness program, hardship shortfall deferral, corporate insurance update, directors' and officers' liability insurance, environmental liability insurance, injuries and damages, production and distribution, computer rental, maintenance and conversion, radio maintenance and repair, management audit expense, consultants for generic proceedings, outside services - other, non-recurring outside services expense, outside services - legal, lobbying expense, corporate training expense, demonstration and selling expense, promotional advertising, market development and engineering studies, economic development deferral amortization, service contract and charge service, servicemen licensing fees, American Gas Association Membership dues, social and service club dues, postage expense, inflation adjustment, payroll taxes, property taxes, income tax expense, and interest synchronization

- Project Manager in the review of Mountaineer Gas Company on behalf of the West Virginia Consumer Advocate Division. Ms. DeRonne and Mr. Larkin prepared written testimony and exhibits in this case, however, the case was settled prior to hearings Issues addressed by Larkin & Associates include Post-test year plant additions, acquisition adjustment, prepayments, working capital, consolidated tax savings, revenues, payroll, pensions, FAS 112, uncollectibles, computer expense, legal costs, advertising, customer relations and training expense

- Project Manager in the review of a rate increase request by Hope Gas, Inc. Ms DeRonne and Mr Larkin prepared written testimony and exhibits in the case. The case was settled prior to hearings. Issues specifically addressed include. post-test year plant additions, consolidated tax savings, revenues, labor costs, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expense

- Key project team member in the review of the rate increase requested by Connecticut Natural Gas Corporation Assisted with the preparation of data requests, analysis of data, on-site review, and preparing testimony, schedules and exhibits Ms. DeRonne also testified as an expert witness in this case. Issues addressed in testimony by Larkin & Associates include: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

- Key project team member in the review of a rate increase request by Columbia Gas Company before the Pennsylvania Public Service Commission Ms. DeRonne prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site, quantified adjustments for a wide range of issues and assisted in the preparation of a report containing the impact of Larkin & Associates adjustments The case was settled prior to the filing of testimony under a "collaborative" negotiating process

- Project Manager in providing assistance to the West Virginia Consumer Advocate Divisions in the conduct of a general investigation of Equitable Gas Company's West Virginia operations The purpose of the investigation was to determine whether Equitable's base rates were just and reasonable Prepared rate base, operating income and revenue requirement schedules, along with addressing accounting issues Issues addressed in the report included discrepancies between the Company's operating reports and the annual reports filed to the Commission, plant allocated from affiliated service company, rent from gas properties, return on service company assets, comparison of cost levels with other utilities, meter reading charges allocated from an affiliate, meter & house regulatory expense, injuries and damages, legal costs, affiliated cost savings, depreciation expense and consolidated income tax savings

- Project leader in the review of a billing dispute between the Navy Public Works Center-Guam and the Guam Power Authority Key issues included the appropriate treatment of certain costs under the FERC USOA, as required under a contract between the two parties Duties included the analysis of Navy and GPA records, on-site review and preparation of final recommendation report and schedules

- Key Project Member Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate increase request by Connecticut Natural Gas Corporation Issues addressed Rate Base, including plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program. Operating Income, including IS mechanism, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense adjustment - outside services, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization

- Performed training seminars on behalf of the Department of Defense, Navy Rate Intervention on Measuring Financial Capabilities of Firms Ms DeRonne prepared the training manuals and participated as one of the instructors. Training was provided to naval contracting employees, engineers and naval officers at five locations.

A complete list of cases in which Ms DeRonne has participated/testified will be provided upon request

Education

- Oakland University - Rochester, MI
  Bachelor of Science: Accounting, April 1991
  Graduated with University Honors
  GPA 3.53 of 4 0
- Continuing education necessary to maintain CPA license

Professional Associations

- Michigan Association of Certified Public Accountants

References

- Richard Sobolewski
  State of Connecticut
  Office of Consumer Counsel
  10 Franklin Square
  New Britain, Connecticut 06051
  (860) 827-2900

- Dan Gimble
  Utah Committee of Consumer Services
  Heber M Wells Building
  160 East 300 South, Room 408
  Salt Lake City, Utah 84111
  (801) 530-6798

- Sam DeFrawi
  Navy Rate Intervention
  CHESNAVFACENGCOM
  Building 212, 4th Floor
  901 M Street, S E
  Washington, D C. 20374
  (202) 685-0130

TINA MILLER

Ms Miller is a staff accountant and regulatory analyst with Larkin & Associates As such, Ms Miller prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research

Relevant Regulatory Experience
Following are examples of recent regulatory cases in which Ms Miller has participated

- Key project team member in the Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation Our task involved performing an extensive investigation of the combined utilities gas system, tariffs, contracts, and operations, and analyzing the combined utilities compliance with market power safeguards adopted in the Commissions Decision D 98-03-073 to ensure open and nondiscriminatory service Ms Miller assisted with the analysis of key issues, drafting of data requests, performed on-site reviews at the company's offices, attended numerous interviews with company personnel, reviewed over 4,000 recorded telephone calls of the Gas Scheduling and Control Departments, and assisted with drafting of the final report and exhibits

- Project Member in the review of Southwest Gas Corporation's (SWG) application to amend its rate schedules Larkin & Associates' testimony focused in the area of revenue requirement. Issues addressed included: rate base, adjustments to operating income, and the relationship between SWG and Utility Partners, Inc, and the costs and resultant litigation associated with a failed merger Ms Miller assisted with the analysis of key issues, and company documents

- Project Member in the review of the merger of CTG Resources, Inc and Energy East Corporation Ms. Miller examined Company filings and documents and researched relevant issues Certain merger issues examined include: the merger's effect on competition in the State of Connecticut; the merger's consistency with public interest, whether it would benefit both consumers and stockholders, whether there were acceptable customer protections in place to ensure effective cost control, how the merger would effect regulation, and whether there were any factors benefiting customers which clearly compel the approval of the merger

- Project Member in the review of the merger application between Energy East and Connecticut Energy Corporation Ms Miller reviewed Company material and responses to data requests The project objective was to evaluate the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control

- Project Member Larkin & Associates was contracted to conduct a financial review of Southern Connecticut Gas Company. Ms. Miller analyzed responses to data requests and Company material. Larkin & Associates recommended adjustments to both rate base and operating income An alternative ratemaking plan and performance based ratemaking plan were both further examined. Specific areas analyzed and addressed. truckline project, conservation expenditures, working capital, incentive pay, payroll, payroll tax expense, pensions; health care benefits and other benefits; early retirement plan expense; outside services expense; computer system maintenance expense; AGA dues expense; age change program cost savings, additional cost savings, amortization of environmental remediation costs; amortization of three-way payment forgiveness plan, uncollectibles, lease income, property tax expense, reduction of income tax reserve, income tax expense, and interest synchronization

- Project Team Member in the rate case filing by Connecticut Natural Gas Corporation. Ms Miller participated in this case by reviewing Company material and analyzing pertinent issues Issues addressed by us in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company Ultimately, the Company's rates were reduced

- Project Member in a review of the application of PacifiCorp for approval of its proposed electric rate schedules and electric service regulations Issues addressed in testimony included: incentive compensation, payroll, pensions/post-retirement benefits, working capital, Bridger Coal Company Rate Base, Environmental Settlements, Revenue Normalization Correction, Distribution Expense Correction, Accounting Write-Offs, Assets under construction write-off, Cholla Assets Under Construction Write-Off, Additional Assets Under Construction Written Off, Obsolete Inventory Write-Offs/Reserve, FERC Contingency Write-Off, Blue Sky Program, Stoel Rives Pricing Settlement, Transition Team Costs, Miscellaneous Outside Service Expense, Annualization of Contract Cost Savings, Dave Johnston (Glenrock) mine closure, systems applications and products software (SAP), re-engineering, 1997 computer software write-down, Company's proposed 1999 software write-off, uncollectible expense, and potential updates (pending additional information from the Company).

- Project Member in an investigation of over-earnings by the Connecticut Light & Power Company Issues presented in testimony included over-earning standards, cause of over earnings, treatment of over-earnings, impact of over-earnings on conditions of NU/ConEd Merger, and the Company's proposed initiatives.

- Project Member in the review of Wisconsin Public Service Corporation's application for a Supply Cost Recovery Plan and Authorization of Monthly Power Supply Cost Recovery Factors for the Calendar Year 2001 Ms Miller assisted by analyzing issues such as additional coal costs for new coal contracts, forecast and historical analysis of hydro plant generation, and reviewing company material

- Key project team member in the review of Delaware Electric Cooperative's Restructuring Plan for Retail Competition Larkin & Associates was retained by the Delaware Public Service Commission (DPSC) to provide consulting services to the Hearing Examiner of the DPSC Duties included review of filings and briefs of the parties, review of the transcript of the hearing, summarize the positions of the parties, and assist in the preparation of the Hearing Examiners Report

- Key project member in the review of Delmarva Power & Light's billing system conversion problems Consulting services were provided to the Hearing Examiner of the Delaware Public Service Commission. Relevant issues addresses included: compensation and economic damages to customers, proration, arbitration procedures Non-economic issues included "reaching back" problem, budget plans, tariff rates on bills, high bill parameters, PriceWaterhouseCoopers audit report, payment posting sequence, emergency phone number, issue list, lost customers, walk-in offices, and a summit for unresolved issues. Duties included review of filings and briefs of the parties, review of the transcript of the hearing, summarize the positions of the parties, and assist in the preparation of the Hearing Examiners Report Project member in the review of Delmarva Power & Light's application for Approval of a Cost Accounting Manual and a Code of Conduct. Ms. Miller assisted by reviewing filings, transcripts, The Cost Accounting Manual , Code of Conduct , and summarize the positions of the parties, and assisting in the preparation of the Hearing Examiners Report.

- Key project member in the review of Chesapeake Utilities Corporation application for Approval of a Cost Accounting Manual and a Code of Conduct. Ms Miller reviewed filings, responses to data requests, the proposed Cost Accounting Manual, and proposed Code of Conduct. She also assisted in drafting a revised Code of Conduct and testimony.

A complete list of cases in which Ms Miller has participated will be provided upon request.

Education

- Eastern Michigan University - Ypsilanti, MI
  Bachelor of Business Administration: Accounting
  April 1996

References

- Greg Doyle
  Minnesota Department of Commerce
  Telecommunications Division
  85 7th Place East, Suite 500
  St. Paul, MN 55101-2198
  (651) 284-4207

- Jack Fulcher
  California Public Utility Commission
  505 Van Ness Avenue
  San Francisco, CA 94102
  (415) 703-2061

- G Arthur Padmore
  Division of the Public Advocate
  820 French Street, 4th Floor
  Wilmington, DE 19801
  (302) 577-5077

MARK S. DADY

Mr Dady is a staff accountant and regulatory analyst with Larkin & Associates As such, he prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research

Regulatory Experience

- Since joining the firm in November 2001, Mr Dady has worked on a diverse range of regulatory projects under the supervision of senior members of the firm He has prepared data requests, analyzed issues, prepared schedules, and assisted in the determination of the jurisdictional revenue requirements for a variety of regulated public utilities

- Project team member in United Illuminating Company's rate case. Larkin & Associates was retained by the Connecticut Office of Consumer Counsel to address the calculation of the revenue requirement and adjustments to the calculations of rate base and net operating income presented in UI's filing Larkin & Associates also addressed the sharing proportions that should be applied if the Department adopts a multi-year rate plan for UI in this proceeding Issues discussed in testimony included rate plan, over-earnings sharing proportions, subsidiary income tax expense, starting point for 2002 rate year rate base, customer deposits, materials and supplies, rate-a-meter timers, injuries and damages reserve, severance expense, rate case expense, other O&M expense increase, ADIT on pension liability and Bad Debt reserve, accrued vacation and related ADIT, Steel Point remediation, depreciation expense, income tax expense correction, interest synchronization, property tax expense, accelerated amortization

- Project team member in the review of Citizens Utilities Company's application for a rate increase. Issues addressed in testimony included: an overall financial summary, accounting concerns, rate base (interim accumulated depreciation, rate year accumulated depreciation, used and useful, deferred income taxes, deferred costs, IRP Twenty Year Plan, PCB Costs, 1999 Windstorm and Hurricane Floyd costs, HQ Arbitration, Working capital), operating income (revenue adjustments, SAO expense, DAO expense, PSO expense, Rate Case Expense, Legal and Regulatory, Income Tax Expense, Tree Trimming) and summary of accounting problems

- Project team member in the review of ACS of Alaska, Inc 's, d/b/a as Alaska Communications Systems, local rate case filing. Issues investigated and analyzed during the project included Depreciation Expense, Accumulated Depreciation, Universal Service Fund Revenue, Management Fees, Customer Deposits, Interest Expense, Donations and Corporate Image Expense, Vancouver Office Rent Expense, Rate Case Expense, Depreciation Study Expense, Uncollectibles, Interest Synchronization, Inter-Company Allocations, Weighted Access Lines and Relative Size Factors, Unusual 2000 Expense for Legal Settlement Costs, AFUDC on Telephone Plant Under Construction, Materials and Supplies Inventory, Cellular Access Revenue, Lost Revenue from Discounts/Promotions, Directory Revenue, Insurance Expense, Bonus Expense and Cobra Expense

- Project team member in the review of ACS of Anchorage, Inc.'s, d/b/a as Alaska Communications Systems, local rate case filing Issues investigated and analyzed during the project included. Depreciation Expense, Accumulated Depreciation, Universal Service Fund Revenue, Management Fees, Customer Deposits, Interest Expense, Donations and Corporate Image Expense, Vancouver Office Rent Expense, Rate Case Expense, Depreciation Study Expense, Uncollectibles, Interest Synchronization, Inter-Company Allocations, Weighted Access Lines and Relative Size Factors, Unusual 2000 Expense for Legal Settlement Costs, AFUDC on Telephone Plant Under Construction, Materials and Supplies Inventory, Cellular Access Revenue, Lost Revenue from Discounts/Promotions, Directory Revenue, Insurance Expense, Bonus Expense and Cobra Expense

- Project team member in the review of ACS of Fairbanks, Inc 's, d/b/a as Alaska Communications Systems, local rate case filing Issues investigated and analyzed during the project included· Depreciation Expense, Accumulated Depreciation, Universal Service Fund Revenue, Management Fees, Customer Deposits, Interest Expense, Donations and Corporate Image Expense, Vancouver Office Rent Expense, Rate Case Expense, Depreciation Study Expense, Uncollectibles, Interest Synchronization, Inter-Company Allocations, Weighted Access Lines and Relative Size Factors, Unusual 2000 Expense for Legal Settlement Costs, AFUDC on Telephone Plant Under Construction, Materials and Supplies Inventory, Cellular Access Revenue, Lost Revenue from Discounts/Promotions, Directory Revenue, Insurance Expense, Bonus Expense and Cobra Expense.

- Project team member in the review of ACS of the Northland, Inc 's, d/b/a as Alaska Communications Systems, local rate case filing Issues investigated and analyzed during the project included· Depreciation Expense, Accumulated Depreciation, Universal Service Fund Revenue, Management Fees, Customer Deposits, Interest Expense, Donations and Corporate Image Expense, Vancouver Office Rent Expense, Rate Case Expense, Depreciation Study Expense, Uncollectibles, Interest Synchronization, Inter-Company Allocations, Weighted Access Lines and Relative Size Factors, Unusual 2000 Expense for Legal Settlement Costs, AFUDC on Telephone Plant Under Construction, Materials and Supplies Inventory, Cellular Access Revenue, Lost Revenue from Discounts/Promotions, Directory Revenue, Insurance Expense, Bonus Expense and Cobra Expense

- Key project team member in the annual audit of Lake State Railway and Huron Leasing Duties included verification of cash receipts and disbursements, payroll, and inventory

A complete list of cases in which Mr Dady has participated will be provided upon request

Education

- Davenport University, Dearborn, MI
  Bachelor of Business Administration, Accounting
  March 2001 – Graduated with High Honors

Reference

Kevin Mitrzyk, Controller
Lake State Railway
323 Newman Street
P O Box 232
East Tawas, MI 48730
(517) 362-0214

APPENDIX II
LARKIN & ASSOCIATES
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Southern Connecticut Gas Company – Recovery of Exogenous Costs; Docket No. 03-11-20

Client: Connecticut Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel to review the Company's request for recovery of six specific items identified by the Company as exogenous costs under its Incentive Rate Plan. Larkin & Associates testimony first addressed the appropriate definition and specific qualifications for items to be considered as exogenous costs under the Company's incentive rate plan. The testimony then addressed the following six specific items for which the Company was requesting an increase in rates for exogenous cost recovery: uncollectible expense, pension expense, other post retirement benefit expense, personal property taxes, raise in Connecticut Corporate Business Tax rate and Three-Way Payment Plan deferrals.

Key participants. Donna DeRonne
Mark Dady

Geographic Location: Connecticut

Contract Duration: 2004

Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Services; Formal Case No. 1016

Client: District of Columbia
Office of Peoples Counsel
113315th Street NW, Suite 500
Washington, DC 20005-2710
(202) 727-3071

Contact. Jennifer Emma

Assignment: Larkin & Associates was retained by the Office of Peoples Counsel to review Washington Gas light Company's proposed incentive rate plan and construction budget as part of its request for an increase in rates Mr. Larkin's testimony focused on the following issues:

- Whether Company's construction budget and construction programs were reasonable.
- Whether the Company's proposal for an incentive-based regulation plan ("IRP") was reasonable and appropriate
- Does the Company need incentives over and above those provided by the traditional rate of return regulation.
- Does the Company's incentive-based regulatory plan serve the best interest of the District of Columbia ratepayers?
- Does the Company's proposed incentive-based regulatory plan provide an appropriate and balanced treatment of ratepayer and shareholderinterests?
- What quantifiable benefits, if any would District of Columbia consumers receive as a result of the Commission's acceptance of the Company's proposed incentive-based regulatory plan?
- Does the Company's proposed earnings sharing mechanism provide an equitable distribution of the costs and benefits to the Company's customer classes?
- Are the proposed customer service quality of service standards appropriate?
- Are the procedures that the Company proposes for adjusting rates without a full base rate proceeding under its proposed incentive-based regulatory plan, reasonable, appropriate and equitable?
- Will an incentive-based regulatory plan be effective for the Company for District of Columbia operations if similar incentive plans are not implemented for the Company's Maryland and Virginia Service territories?
- What impact would the Company's proposed incentive-based regulatory plan have on consumer input to the rate adjustment process?
- What has been the experience with this type of IRP in states that have implemented such plans?

Key Participants: Hugh Larkin, Jr.
Donna DeRonne

Geographic Location. Washington, D.C

Contract Duration. 2003

ENSTAR Natural Gas Company and Alaska Pipeline Company, Docket No. U-00-88

Client:	Regulatory Commission of Alaska, Public Advocacy Section 701 West Eighth Avenue, Suite 300 Anchorage, AK 99501 (907) 263-2151
Contact:	Lew Craig, Chief, Public Advocacy Section
Assignment.	Larkin & Associates was retained by the Public Advocacy Section of the Regulatory Commission of Alaska to review the Cost of Service Study and Rate Design proposals filed by ENSTAR. The objective of this review was to assess whether or not the Cost of Service Study and Rate Design proposed by ENSTAR will result in reasonable rates, and to recommend modifications as appropriate to ENSTAR's proposals, keeping in mind the interests of the ENSTAR's residential and small commercial customers. Issues addressed in testimony included: postage stamp rates, customer charge, gas cost, declining block rates, and proposed rates for residential and small commercial customers. Issues addressed in reply testimony included allocation of transmission costs, allocation of distribution system cost, derivation of peak demand factor, costs and revenues from Agrium Plant, Aurora testimony, and Northern Eclipse testimony.
Key Participants:	Ralph C. Smith
Geographic Location:	Alaska
Contract Duration:	2003

Environmental Protection Agency – Comments concerning proposal rule

Client:	State of New Jersey Department of Law and Public Safety, Division of Law Richard J. Hughes Justice Complex 25 Market Street P.O. Box 093 Trenton, NJ 08625
Contact:	Ruth Carter, 609/292-6945
Assignment:	Larkin & Associates was retained by the New Jersey Department of Law and Public Safety to assist in submitting comments to the Environmental Protection Agency regarding the EPA's proposed rule published on December 31, 2002 at 67 Federal Register 80290 entitled, "Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR): Routine Maintenance, Repair and Replacement " L&A assisted the NJ Department of Law with research and drafting of the comments submitted to the EPA.
Key participants:	Hugh Larkin, Jr. and Ralph Smith

Geographic Location. New Jersey

Contract Duration: 2003

Yankee Gas Service Application for a Rate Increase, Phase 1-2002 IERM, Docket No. 01-05-19 REO3

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel to conduct a review of Yankee Gas Services Company's application for an increase in rates. Larkin & Associates is assist the OCC by reviewing models used by Yankee Gas to evaluate the economics of each potential system expansion project for which it is requesting DPUC approval in the current docket. This includes obtaining and reviewing such models for compliance with the DPUC established criteria, reviewing the inputs for reasonableness (to the extent feasible) and for changes from the assumptions used by Yankee Gas in its last rate case, reviewing information contained in the Yankee Gas filing and provided by Yankee in response to data requests, reviewing information on system expansion projects from the prior Yankee Gas rate case and assisting OCC with discovery, cross and briefing.
Key participants:	Ralph C. Smith Mark Dady
Geographic Location:	Connecticut
Contract Duration:	September 2002 – March 2003

Tampa Electric Company dba Peoples Gas System; Docket No. 020384-GU

Client:	Office of the Public Counsel 111 W. Madison - St. 801 Tallahassee, Florida 32399-1400 (850) 488-9330
Contact:	Rick Mann
Assignment:	Larkin & Associates was retained by the Florida Office of Public Counsel to review Peoples Gas System's request for an increase in rates. Our testimony addressed projected additions to plant in service; construction work in progress; off-system sales; charges from and contract with affiliated sales and marketing entity; separation of employees into non-regulated sales and marketing entity; charges from parent company and affiliates; promotional programs; advertising expense; employee levels; incentive compensation; employee benefits; trending adjustments; and impact of Economic Stimulus Package signed into law on March 9, 2002 on deferred income taxes.
Key Participants:	Donna DeRonne Helmuth W. Schultz, III

Geographic Location. Florida

Contract Duration: 2002

Questar Gas Company, Docket No. 02-057-02

Client:	Committee of Consumer Services Heber M. Wells Building, Room 408 160 East 300 South, P.O. Box 146782 Salt Lake City, Utah 84114-6782 (801) 530-6674
Contact:	Dan Gimble
Assignment:	Larkin & Associates was under contract with the Committee of Consumer Services to review the application for an increase in rates and charges filed by Questar Gas Company. Our testimony addressed the following issues: Appropriate test year, revenues, declining customer usage, contributions in aid of construction, gain on sale of property, corporate cost allocations, employee levels, charges from and relationship with unregulated affiliate, incentive compensation, uncollectibles, various expense items, rate of return adjustment from affiliates, and tax credits.
Key Participants:	Donna DeRonne Hugh Larkin, Jr
Geographic Location:	Salt Lake City, Utah
Contract Duration:	2002

Yankee Gas Services Company

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel to conduct a review of Yankee Gas Services Company's application for an increase in rates. Issues addressed in testimony included system expansion project, working capital, regulatory pension liability, SERP, merger synergy adjustment, fuel diversity fund, marketing expense, payroll, incentive compensation, payroll-related expenses, benefit expenses, inflation adjustment, uncollectible and hardship forgiveness/matching payment plan expenses, AGA dues expense, environmental remediation costs, gain on sale of property, property tax refund, property tax expense, income tax expense, and interest synchronization.
Key participants:	Helmuth W. Schultz, III Donna DeRonne
Geographic Location:	Connecticut
Contract Duration:	2001

PG&E 1999 Rate Case

Client:	Department of the Navy Director, Navy Rate Intervention CHESNAVFACENGCOM Building 212, 4th Floor 901 M Street, S.E. Washington, D.C. 20374-5018 (202) 685-0130
Contact:	Sam DeFrawi
Assignment:	Larkin & Associates was retained by the Department of the Navy to analyze PG&E's application for a rate increase, including its testimony, exhibits and workpapers. We presented testimony on behalf of the Navy representing the Department of Defense and all other Federal Executive Agencies (Navy) to address the following issues: GRC Policy, Electric Revenues at Present Rates, Electric Generation Expenses, Gas Revenues at Present Rates, Other Operating Revenues, Total Compensation Expense, Administrative & General Expenses, Injuries and Damages (Account 925), Pensions and Benefits (Account 926), Long-term Disability/FAS Expense, Meter Reading, Payroll Taxes, Diablo Canyon Decommissioning, Humboldt Decommissioning, Fossil and GeoThermal Decommissioning, and the ORA's Results of Examination.
Key participants	Ralph C. Smith Donna DeRonne
Geographic Location:	California
Contract Duration:	1999 – 2000

Connecticut Natural Gas Company; Docket No. 99-09-03, Phase II

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review Connecticut Natural Gas Company's proposed performance based ratemaking plan. Our testimony addressed numerous deficiencies with the Company's proposed plan as well as the following issues: the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key Participants: Hugh Larkin Jr.
Donna DeRonne

Geographic Location. Connecticut

Contract Duration: 2000

Southwest Gas Corporation; Docket No. G-01551A-00-0309

Client:	Arizona Corporation Commission 1200 West Washington Street Phoenix Arizona 85007 (602) 542-0745
Contact:	Janice Alward
Assignment:	Larkin & Associates was retained by the Arizona Corporation Commission to review Southwest Gas Corporation's application to amend its rate schedules. The testimony submitted by Larkin & Associates concentrates in the area of revenue requirement. Issues addressed in testimony include: rate base, adjustments to operating income, the relationship between SWG and Utility Partners, Inc., and the costs and resultant litigation associated with a failed merger.
Key Participants:	Donna DeRonne Helmuth W. Schultz, III Ralph Smith Tina Miller
Geographic Location:	Arizona
Contract Duration:	2000 - 2001

Southern Connecticut Gas Company; Docket No. 99-04-18, Phase II

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate case filing by Southern Connecticut Gas Company. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Issues addressed by us in our testimony included: conservation expenditures; working capital; payroll; incentive compensation, pensions; PBOP; early retirement plan expense; outside services; computer system maintenance expense; age change program cost savings; uncollectibles; environmental remediation amortization; property taxes; reduction of income tax reserve; and federal income taxes.

Key Participants: Helmuth W. Schultz, III
Donna DeRonne

Geographic Location: Connecticut

Contract Duration: 1999

Questar Gas Company; Docket No. 99-057-20

Client: Committee of Consumer Services
Heber M. Wells Building
160 East 300 South, P.O. Box 146782
Salt Lake City, Utah 84114-6782
(801) 530-6674

Contact: Dan Gimble

Assignment: Larkin & Associates was under contract with the Committee of Consumer Services to review the application for an increase in rates and charges filed by Questar Gas Company. Our testimony addressed the following issues: Revenues, gain on sale of property, advertising expense, incentive compensation, uncollectibles, phantom stock correction, rate of return adjustment from affiliates and contingent liabilities. The revenue requirement portion of the case was settled prior to hearings.

Key Participants. Hugh Larkin, Jr.
Donna DeRonne

Geographic Location: Salt Lake City, Utah

Contract Duration: Early 2000

Southern Connecticut Gas Company; Docket No. 99-04-18, Phase III

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review Southern Connecticut Gas Company's proposed performance based ratemaking plan. Our testimony pointed out numerous problems with the Company's proposed plan. Testimony also addressed the Company's estimated merger synergies, treatment of goodwill/acquisition premium and marketing program costs in calculating the return on equity for regulatory purposes, and the appropriate treatment of the PGA under any earnings sharing plans and several other issues inherent in the Company's proposal. Mr. Larkin & Ms. DeRonne also proposed an alternative performance based ratemaking plan for consideration.

Key Participants: Hugh Larkin, Jr.
Donna DeRonne

Geographic Location: Connecticut

Contract Duration: 2000

Connecticut Natural Gas Corporation; Docket No. 99-09-03, Phase I

Client:	State of Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051-2644 (860) 827-2900
Contact:	Richard Sobolewski Gene Koss
Assignment:	Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate case filing by Connecticut Natural Gas Corporation. Our review recommended a reduction in the Company's rates as opposed to the increase requested by the Company. Ultimately, the Company's rates were reduced. Issues addressed by us in testimony included: injuries and damages reserve, FAS 106 deficiency deferred debit, working capital, uncollectibles, hardship arrearage program, inflation, insurance, outside services, commission assessments, maintenance of plant, public relations expense, and property tax expense.
Key Participants:	Hugh Larkin, Jr. Helmuth W. Schultz, III Donna DeRonne Tina Miller
Geographic Location.	Connecticut
Contract Duration:	1999

Black Mountain Gas Division of Northern States Power Company, Page Operations; Docket No. G-03493A-98-0705

Client: Arizona Residential Utility Consumer Office
2828 N. Central Avenue, Suite 1200
Phoenix, Arizona 85004
(602) 279-5659

Contact: Marylee Diaz Cortez

Assignment: Larkin and Associates was retained by the Residential Utility Consumer Office to review Black Mountain Gas Division of Northern States Power Company Page, Operation's rate increase request. Testimony submitted addressed the following issues: revenue annualizations, weather normalization, late payment revenues, employee benefits, corporate overhead allocation, insurance expense, directors' fees, advertising expense, property tax expense, rate case expense and income tax rates. This was the first rate case subsequent to the purchase of Black Mountain Gas by Northern States Power Company. Consequently, corporate allocations were of particular concern in this case.

Key Participants. Hugh Larkin, Jr.
Helmuth W. Schultz, III
Donna M. DeRonne

Geographic Location: Arizona

Contract Duration: February 1999 - July 1999

Energy East Corporation and CTG Resources; Application No. 99-08-09

Client:	Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates were asked to review the merger of CTG Resources, Inc. and Energy East Corporation. Certain merger issues examined include: the merger's effect on competition in the State of Connecticut; the merger's consistency with public interest; whether it would benefit both consumers and stockholders; whether there were acceptable customer protections in place to ensure effective cost control; how the merger would effect regulation; and whether there were any factors benefiting customers which clearly compel the approval of the merger.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne Tina Miller
Geographic Location:	Connecticut
Contract Duration:	1999-2000

Energy East Corporation and Connecticut Energy Corporation; Application No. 99-07-20

Client: Connecticut Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051

Contact: Richard Sobolewski

Assignment: The Connecticut Office of Consumer Counsel requested the assistance of Larkin & Associates in the review of the merger application between Energy East and Connecticut Energy Corporation. Larkin evaluated the merger in regards to the effect on competition in Connecticut, whether the merger is a benefit to both consumers and shareholders, effect on regulation, any factors which compels the merger for the benefit of customers, and whether there are acceptable customer protections in place to ensure affective cost control.

Key Participants: Hugh Larkin, Jr.
Donna DeRonne
Tina Miller

Geographic Location: Connecticut

Contract Duration: 1999-2000

Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation

Client: California Public Utilities Commission

Contact: Jack Fulcher
Energy Division
505 Van Ness Avenue, Room 4205
San Francisco, CA 94102
(415) 703-1711

Assignment: Our task involved performing an extensive investigation of the combined utilities gas system, tariffs, contracts, and operation. An analysis of the combined utilities compliance with market power safeguards adopted in the Commissions Decision D.98-03-073 to ensure open and nondiscriminatory service was conducted. This included the Company's agreement to divest of its gas-fired generation facilities, and its options to purchase the California facilities of Kern River and Mojave Pipelines to non-affiliates of the merged company by the specified deadlines, and the Company's compliance with the 25 Remedial Measures adopted by the Commission as well as a review of market power.

Our approach to the work involved formal data requests, approximately 100 interviews with numerous Company personnel, and an extensive review of information including the review of over 4,000 recorded phone calls in key SoCalGas departments including Gas Scheduling and Gas Control as part of the testing for compliance an non-discrimination. It also involved frequent meetings and discussions with Staff personnel.

Key Participants: Hugh Larkin, Jr.
Ralph C. Smith
Tina Miller

Geographic Location: Los Angeles and San Diego, California

Contract Duration: 1999- 2000

Southern Connecticut Gas Company; Docket No. 99-04-18

Client:	Connecticut Office of Consumer Counsel 10 Franklin Square New Britain, Connecticut 06051
Contact:	Richard Sobolewski
Assignment:	Larkin & Associates was retained by the Connecticut Office of Consumer Counsel to conduct a financial review of Southern Connecticut Gas Company. Larkin & Associates recommended adjustments to both rate base and operating income. An alternative ratemaking plan and performance based ratemaking plan were both further examined. Specific areas analyzed and addressed: truckline project; conservation expenditures; working capital; incentive pay; payroll; payroll tax expense; pensions; health care benefits and other benefits; early retirement plan expense; outside services expense; computer system maintenance expense; AGA dues expense; age change program cost savings; additional cost savings; amortization of environmental remediation costs; amortization of three-way payment forgiveness plan; uncollectibles; lease income; property tax expense; reduction of income tax reserve; income tax expense; and interest synchronization.
Key Participants:	Helmuth W. Schultz, III Donna M. DeRonne Tina Miller
Geographic Location:	Connecticut
Contract Duration:	1999-2000

Southern Connecticut Gas Company; Docket No. 97-12-21

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski
Gene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to conduct a financial review of Southern Connecticut Gas Company. Our review determined that the Company was over-earning and a reduction in rates was recommended. As a result of the investigation, the Company was required to either voluntarily reduce rates or file a full rate case proceeding before the Connecticut Department of Public Utility Control. Issues addressed by us in our testimony included: plant-in-service; conservation expenditures; working capital; inflation; payroll; incentive compensation; pensions; PBOP; outside services; advertising; rent expense; leak survey costs; uncollectibles; Conservation Adjustment Mechanism; depreciation, amortization; property taxes; reduction in state income tax rate; federal income taxes; and cost savings from sale and lease back of liquidated natural gas facility.

Key Participants: Helmuth W. Schultz, III
Donna DeRonne

Geographic Location: Connecticut

Contract Duration. 1998

Pacific Gas & Electric Company; Attrition and Application for a Rate Increase, Docket No. 00-07-043

Client:	Department of the Navy Director, Navy Rate Intervention CHESNAVFACENGCOM Building 212, 4th Floor 901 M Street, S.E. Washington, D.C. 20374-5018 (202) 685-0130
Contact:	Sam DeFrawi
Assignment:	Larkin & Associates was retained by the Department of the Navy to review and analyze the issues and determine whether PG&E is entitled to the requested rate increase. Relevant issues included: productivity, customer growth, usage growth, cost control, PG&E's claim of foregoing a $43 million increase of Gas Distribution ARA, overearnings, and actual vs. authorized ROE.
Key participants.	Ralph C. Smith
Geographic Location:	California
Contract Duration:	2000

Pacific Gas & Electric Company; Docket No. 97-12-020

Client: Department of the Navy
Director, Navy Rate Intervention
CHESNAVFACENGCOM
Building 212, 4th Floor
901 M Street, S.E.
Washington, D.C. 20374-5018
(202) 685-0130

Contact: Sam DeFrawi
Donald Coates

Assignment: Larkin & Associates was retained by the Department of the Navy and all other Federal Executive Agencies to perform utility revenue requirement studies of Pacific Gas & Electric Company in connection with the company's 1999 general rate case. Our testimony addressed a number of issues affecting PG&E's jurisdictional revenue requirements for its gas and electric operations, including the following: revenue, total compensation, other post-employment benefits accrual amortization (FAS 112), pension expense, employee transition expense for hydro facilities, nuclear decommissioning expense, fossil and geothermal decommissioning expense, injuries and damages, and administrative and general expense.

Key Participant: Ralph C. Smith

Geographic Location: California

Contract Duration: 1998

Citizens Utility Company, Northern Arizona Gas Division; Docket No. E-1032-95-473

Client: Arizona Corporation Commission
Utilities Division
1200 W. Washington
Phoenix, Arizona 85007
(602) 542-0745

Contact: Janice Alward
Chris Kempley

Assignment: Larkin & Associates' reviewed Citizens Utilities Company, Northern Arizona Gas Division's request for an increase in rates. We were responsible for analyzing rate base and net operating income issues, quantifying adjustments, and writing testimony. Specific issues addressed included: construction work in progress; AR-13 amounts; Stamford Administrative Office common plant balance; accumulated deferred income taxes; acquisition adjustment; cash working capital; payroll expense; incentive compensation; FAS 106 expense; property taxes, legal, regulatory, and special studies expense; Target: Excellence expense; injuries and damages expense; insurance expense, Stamford Administrative Office expense; Phoenix Administrative Office expense; gas sales promotional expense; A&G expense disallowance; income tax rates. We also addressed the ratemaking treatment of the Company's build-out program. Furthermore, we coordinated with ACC Staff in addressing purchased gas costs. This case was settled.

Key Participants: Ralph C. Smith

Geographic Location: Phoenix, Arizona

Contract Duration: December 1995 - October 1996

Columbia Gas of Pennsylvania (Collaborative)

Client:	Pennsylvania Office of Consumer Advocate 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Tad Berger
Assignment:	Larkin & Associates was hired by the Pennsylvania Office of Consumer Advocate to review Columbia Gas Company's request to increase its rates. We prepared discovery, reviewed responses, reviewed documents and interviewed Company employees on-site at their Columbus, Ohio office, quantified adjustments for a wide range of issues, and prepared a report containing the impacts of our adjustments. We also quantified various alternatives as part of the "collaborative" negotiating process that resulted in the final agreement concerning the amount of rate increase.
Key Participants:	Ralph C. Smith Donna DeRonne
Geographic Location:	Pennsylvania
Contract Duration:	1995 - 1996

Missouri Gas Energy; Case No. GR-96-285

Client:	Missouri Public Service Commission Staff P.O. Box 360 Jefferson City, Missouri 65102
Contact:	Chuck Hyneman, Case Coordinator, (816) 889-3551 Roy Boltz, Lead Auditor, (573) 751-4890 John Himmelberg, Jr., Assistant General Counsel, (573) 751-7485
Assignment:	Larkin & Associates was retained by the Missouri Public Service Commission Staff to review Missouri Gas Energy's ("MGE") affiliated transactions and Southern Union Company's corporate costs. This was the first rate case review after the acquisition by Southern Union of MGE. MGE and Southern Union's previously owned gas distribution operations (located in Texas) were approximately the same size in terms of annual revenues and rate base. This project involved a thorough review of the corporate cost allocation model that was developed after the merger occurred. Testimony addressed the following issues: common plant - Austin, Texas office; accumulated deferred income taxes; corporate allocations; New York Stock Exchange listing fees (initial and ongoing) for the new company; executive stock options and stock-based compensation; SFAS 123; incentive compensation; pensions and SFAS 106 nonpension post retirement benefits; budgeting of corporate costs and employee levels; executive offices in New York City; treatment of salary expense for geographically removed executives; affiliated transactions; KellAir, an affiliated supplier of airplane passenger service; allocation factors; use of time reporting for corporate executives.
Key Participants:	Ralph C. Smith
Geographic Location:	Missouri
Contract Duration:	1996

Equitable Gas Company; Case No 96-0059-G-GI

Client: Consumer Advocate Division
West Virginia Public Service Commission
7th Floor, Union Building
723 Kanawha Boulevard, East
Charleston, West Virginia 25301
(304) 558-0526

Contact: Billy Jack Gregg
Byron Harris

Assignment: Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to assist in the conduct of a general investigation of Equitable Gas Company's ("Equitable") West Virginia operations. The overall purpose of the investigation, which was initiated by the Consumer Advocate Division, was to determine whether Equitable's base rates, which were set over five years prior, were just and reasonable. Since there was not a rate case filed by the Company, we were responsible for preparing the rate base, operating income and revenue requirement schedules, along with addressing all accounting issues. Issues addressed in our final report include: discrepancies between the Company's operating reports and the annual reports filed to the West Virginia Public Service Commission; plant allocated from an affiliated service company; rent from gas properties; return on service company assets, comparison of cost levels with other West Virginia utilities; meter reading charges allocated from an affiliate; meter & house regulator expense; injuries and damages; legal costs; affiliated cost savings; depreciation expense; and consolidated income tax savings.

Key Participant: Donna DeRonne

Geographic Location: Pittsburgh, Pennsylvania; West Virginia

Contract Duration: May 1996 - November 1996

Peoples Natural Gas Company; Docket No. INU-94-2

Client: Iowa Utilities Board
Lucas State Office Building
Des Moines, Iowa 50319
(515) 281-5541

Contact: Don Judisch

Assignment: Larkin & Associates was retained by the Iowa Utilities Board to perform an audit of Peoples Natural Gas Company's direct assignment and allocation of costs to its non-regulated operations in the State of Iowa. The purpose of our audit was to assess if the Company complied with its 1995 Cost Allocation Manual and to evaluate the propriety of the allocation methods embodied within the Manual.

Key Participants: Helmuth W. Schultz, III

Geographic Location: Omaha, Nebraska

Contract Duration: July 1996 - December 1996

Connecticut Natural Gas Corporation; Docket No 95-02-07

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644

Contact: Richard Sobolewski
Eugene Koss

Assignment: Larkin & Associates was retained by the Office of Consumer Advocate of the State of Connecticut to review the rate increase requested by Connecticut Natural Gas Corporation. Issues addressed in testimony by Larkin & Associates include: natural gas vehicles, software additions, working capital, accounts payable, materials and supplies, deferred credits, deferred conservation expense, economic development, sales, late payment revenue, payroll, executive compensation, incentive compensation, pensions, employee benefits, uncollectibles, hardship arrearage forgiveness program, hardship shortfalls, corporate insurance, D&O insurance, environmental liability insurance, injuries and damages, production and distribution expense, computer costs, legal expense, training costs, demonstration and selling, promotional advertising, market development, service contracts, dues, inflation and taxes.

Key Participants: Hugh Larkin, Jr.
Helmuth W. Schultz, III
Donna DeRonne

Geographic Location: Connecticut

Contract Duration: 1995

Mountaineer Gas Company; Case No. 95-0011-G-42T

Client:	Consumer Advocate Division West Virginia Public Service Commission 7th Floor, Union Building 723 Kanawha Boulevard, East Charleston, West Virginia 25301 (304) 558-0526
Contact:	Billy Jack Gregg Byron Harris
Assignment:	Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to review the rate increase request by Mountaineer Gas Company in regards to revenue requirement issues. Rate base items addressed include: Post test year plant additions, acquisition adjustment, prepayments and working capital. Operating income areas addressed include: consolidated tax savings, revenues, payroll, pensions, FAS 112, uncollectibles, computer expense, legal costs, advertising, customer relations expense, and training expense.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne
Geographic Location:	Charleston, West Virginia
Contract Duration:	February 1995 - June 1995

Hope Gas, Inc.; Case No. 95-0003-G-42T

Client:	Consumer Advocate Division West Virginia Public Service Commission 7th Floor, Union Building 723 Kanawha Boulevard, East Charleston, West Virginia 25301 (304) 558-0526
Contact:	Billy Jack Gregg Byron Harris
Assignment:	Larkin & Associates was retained by the Consumer Advocate Division of the State of West Virginia to review the rate increase request by Hope Gas, Inc., specifically as it relates to revenue requirement issues Examples of items specifically addressed in testimony include: post test year plant additions, consolidated tax savings, revenues, labor expense, FAS 106, benefits, Employee Appliance Purchase Plan, corporate charges, affiliated charges, advertising and injuries and damages expenses.
Key Participants:	Hugh Larkin, Jr. Donna DeRonne
Geographic Location:	Charleston, West Virginia
Contract Duration:	February - June, 1995

UGI Utilities, Inc. - Gas Division; Docket No. R-953297

Client:	Pennsylvania Office of Consumer Advocate 555 Walnut Street Forum Place, 5th Floor Harrisburg, PA 17101-1923 (717) 783-5048
Contact:	Mark Shostak Diana Dusman
Assignment:	Larkin & Associates was employed by the Pennsylvania Office of Consumer Advocate ("OCA") to review gas distribution utility's filing for rate increase and compute adjusted revenue requirement, rate base and net operating income. Testimony addressed adjustments to rate base for cash working capital and adjustments to net operating income for the following: Revenue from Customer in Chapter 11 Bankruptcy; Rate IS/IL sales; Gasmark (an affiliated gas marketing entity) net revenues, Group Hospital Expense, Reading is Fundamental; Promotional Allowances/Demand Side Management; Heating Efficiency Program; High Efficiency Water Heating Program; Air Conditioning Program; Natural Gas Powered Vehicle Program; Industry Organization Dues/Company Memberships; Rate Case Expense; Employee Perks, FAS 106 Expense; FAS 112 Expense; Outside Services - Legal; Outside Services - Other; Outside Service Other - Management Audit, United Valley Insurance Company, Repairs to Gas Preparation Equipment; Payroll; Annual Bonus Plan, Injuries and Damages, Provision for Large Claims Paid, Small Claims; Insurance Expense; Economic Depreciation; Reading Service Building Renovations; Non-Qualified Executive Retirement Plan; Directors' Pension, Holding Company - Holiday Parties & Misc Employee Activities, Holding Company - Depreciation/Amortization Credit, Holding Company - Membership Dues; Holding Company - Employee Business Expense; Holding Company - United Way Expenses; Relocation Expense; Employee Hiring Expense, Account 908 - Customer Assistance Expense, Customer Service Information Expenses Amortization, Storm Damage; Low Income Self Help Program; Uncollectibles; Payroll Taxes; PUC assessment; Interest Synchronization, and Competitive Adjustment.
Key Participants:	Ralph C. Smith
Geographic Location:	Harrisburg, PA
Contract Duration:	1995

East Ohio Gas Company and The River Gas Company; Docket No. 93-2006-GA-AIR

Client: Office of Consumers' Counsel
Planning, Policy and Research
77 South High Street, 15th Floor
Columbus, Ohio 43266-0550
(614) 466-8574

Contact: Kenneth Rosselet, Jr.
Maria Byrd

Assignment. Larkin & Associates was employed by the Office of Consumers' Counsel of Ohio ("OCC") to review and evaluate the material filed by the River Gas Company and the East Ohio Gas Company, the PUCO Staff, and any other parties to the proceedings, relating to FAS 106 (post employment benefits other than pensions) and FAS 112 (employer's accounting for post employment benefits.) Review included, but was not limited to, Company testimony and standard filing requirements, responses to discovery, Company workpapers, the Staff Report, Staff workpapers, actuarial studies supporting the accrual of postretirement benefits, the joint comments and reply comments filed by the Customer Coalition in Case No. 92-1751-AU-COI, the entries, Findings and Orders, Applications, Comments and Reply Comments filed under Case Nos. 92-1751-AI-COI, 93-398-GA-AAM and 93-397-GA-AAM. This case was settled.

Key Participants: Ralph C. Smith

Geographic Location: Columbus, Ohio

Contract Duration: 1994-1995

CNG Transmission Corporation; Docket No. RP94-96

Client: State of Pennsylvania
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
(717) 783-5048

Contact: Linda Smith

Assignment: Larkin & Associates was employed by the Pennsylvania Office of Consumer Advocate ("OCA") to review the rate increase requested by CNG Transmission Corporation. The following services were provided to the Pennsylvania Consumer Advocate: Analysis of the Company's filing, preparation of interrogatories and participation in other discovery activities; Preparation of responses to interrogatories propounded upon the OCA by other parties; Analysis of the Company's direct and rebuttal testimony, assistance in preparing cross-examination and attendance during such cross-examination. Preparation of direct testimony and rebuttal testimony and submit to cross-examination thereon. Technical assistance in the preparation of briefs. Issues addressed in testimony included: ratemaking treatment of extraordinary gas loss at CNG Transmission Corporation; treatment of costs incurred by CNGT associated with the Company's violations of environmental laws, and; the amortization period to be applied to CNGT's FAS 106 regulatory asset.

Key Participants: Ralph C. Smith

Geographic Location: Harrisburg, Pennsylvania

Contract Duration: 1994-1995

Indiana Gas Company; Cause No. 39353, Phase II

Client:	Office of Utility Consumer Counselor Indiana Government Center North 100 N. Senate Avenue, Room N501 Indianapolis, Indiana 46204 (317) 232-2494
Contact:	Robert Glennon
Assignment:	Larkin & Associates was under contract with the Indiana Office of the Utility Consumer Counselor to review issues pertaining to Statement of Financial Accounting Standards No 106 (FAS 106) and the rate recovery of costs for postretirement benefits other than pensions (OPEB) requested by Indiana Gas Company (IGC). Our testimony summarized the background and requirements of FAS 106, discussed IGC's proposed ratemaking treatment of FAS 106; identified concerns regarding the FAS 106 accrual, and recommended alternatives to full accrual for recovery of OPEB expenses through rates.
Key Participants:	Hugh Larkin, Jr.
Geographic Location:	Indianapolis, Indiana
Contract Duration:	1993

Connecticut Natural Gas Corporation; Docket No. 93-02-04

Client: State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051-2644
(860) 827-2900

Contact: Richard Sobolewski

Assignment: Larkin & Associates was retained by the Office of Consumer Counsel of the State of Connecticut to review the rate increase request by Connecticut Natural Gas Corporation. Issues addressed: Rate Base; including plant additions, accumulated depreciation - plant additions, air conditioning rebate program, working capital - cost of gas, working capital - O&M, deferred credits, hardship arrearage forgiveness program. Operating Income; including IS mechanism, residential late payment charge revenues, sale of automatic meter reading assets, production and distribution - LNG facility, rent expense - O&A center, payroll, employee benefits, pension expense, removal of certain employee benefits, matching gift program, personal use of Company vehicles, directors' and officers' liability insurance, outside services - legal, rate case expense, economic development expense, uncollectibles, lobbying expense adjustment - outside services, membership dues, adjustment for miscellaneous expenses, general inflation adjustment, CIS/DCIS depreciation expense, property taxes, income tax expense, interest synchronization.

Key Participants: Hugh Larkin, Jr.
Helmuth W. Schultz, III
Donna DeRonne

Geographic Location: Hartford, Connecticut

Contract Duration: June - October, 1993

Minnegasco; Docket No. G008/C-91-942

Client: Minnesota Department of Public Service
Suite 200
121 7th Place East
St. Paul, Minnesota 55101-2145
(612) 297-1773

Contact: Marya White, Supervisor
Sundra Bender

Assignment: Larkin & Associates was assigned to review the January 20, 1993 filing of the Minnesota Alliance for Fair Competition against Minnegasco (MAC) and to analyze the July 1993 filing by Minnegasco in response to MAC's filing. Larkin & Associates' analysis of Minnegasco's July 1993 filing was intended to determine whether Minnegasco had adequately responded to the allegations made by MAC. Also and more specifically, Larkin & Associates was requested to determine whether Minnegasco's Cost Apportionment Manual provides a means of:

1) Determining whether costs can be identified;
2) Determining if an allocation process is reasonable such that: a) all direct costs are allocated, b) the remaining common costs to be allocated are reasonable; and c) the allocator being used is reasonable.
3) Determining if the allocation process is auditable; and
4) Determining if an audit trail exists.

Key Participants: Helmuth W. Schultz, III

Geographic Location: St. Paul, Minnesota

Contract Duration: 1993

Mountain Fuel Supply Company; Docket No. 93-057-01

Client: Committee of Consumer Services
Heber M. Wells Building
160 East 300 South, P.O. Box 146782
Salt Lake City, Utah 84114-6782
(801) 530-6674

Contact: Dan Gimble

Assignment: Larkin & Associates was under contract with the Committee of Consumer Services to review the application for an increase in rates and charges filed by Mountain Fuel Supply Company on April 2, 1993. Our testimony addressed the Company-proclaimed impact on its working gas inventory and labor requirements resulting from FERC Order 636. Another issue of paramount importance was unbilled revenue. Larkin & Associates proposed that the Company's cumulative unbilled revenue balance be amortized into rates over a period of five years. Other issues addressed in testimony were: Cash Working Capital, Accumulated Deferred Income Taxes; "Banked" Vacation; Equal Payment Plan; Payroll Expense; Overtime Expense; Stock Purchase Plan Expense; O&M Expense Percentage; Payroll Taxes; Executive Incentive Retirement Plan; Supplemental Executive Retirement Plan; Postretirement Benefits Other Than Pensions; and Consolidated Income Taxes.

Key Participants. Hugh Larkin, Jr.

Geographic Location: Salt Lake City, Utah

Contract Duration: May 1993 - October 1993

Citizens Utilities-Arizona Gas Division, Docket No. E-1032-93-111

Client: Residential Utility Consumer Office
2828 N. Central Avenue, Suite 1200
Phoenix, Arizona 85004
(602) 279-5659

Contact: Marylee Diaz Cortez

Assignment: Larkin and Associates was retained by Residential Utility Consumer Office to review Citizens Utilities-Arizona Gas Division's rate increase request. Testimony addressed the following issues: Construction Work in Progress, Acquisition Adjustment; Common Plant - Stamford Administrative Office; AGD Four-Factor Allocator Specific SAO Common Plant Disallowances; Harvey, Louisiana Administrative Office Plant; Accumulated Depreciation; Accumulated Deferred Income Taxes; Materials & Supplies; Customer Deposits; Cost-Free Capital -- Warm Spirit Program; Cash Working Capital; Revenue Lag, Amortizations; Payroll Lag; Payroll Tax Lag, Check Clearing Lag; Income Tax; Revenue Annualization; Weather Normalization; Postage Expense; Rate Case Expense; Stamford Administrative Office Expenses; Harvey Administrative Office Expense; Payroll Expense; Payroll Taxes; Employee Benefits; Pension Expense; Supplemental Pension Expense; Group Medical Insurance Expense; FAS 106 Accrual; Incentive Compensation; Directors' and Officers' Liability Insurance; Target. Excellence quality program training cost; Supplier Billing Error; Depreciation Expense; Industry Association Dues; "Wally Bucks" as promotional expense; Donations; Social Organization Dues; Other Expenses that Are Inappropriate for Ratemaking; Interest Synchronization; and Build-out Program.

Key Participants: Ralph C. Smith

Geographic Location: Arizona

Contract Duration: 1993

Philadelphia Electric Co.; In the Matter of Re: Dennis F. Haley et al v. PECO

Client:	Delaware Valley Chapter PCAUUP 1408 E. Mermaid Lane Philadelphia, Pennsylvania 19118
Contact:	Dennis F. Haley
Assignment.	Larkin & Associates was retained to audit the accounting records of Philadelphia Electric Company's gas operations with a specific focus on the Gas House Heating Service Contract Program. The purpose of our audit was to determine the propriety of the Company's recording of revenue and expenses for the Contract Service Program. In addition, we attempted to determine whether the Contract Service Program was subsidized by ratepayers' monies and whether the price of the program was below an average variable cost.
Key Participants:	Helmuth W. Schultz, III
Geographic Location:	Philadelphia, Pennsylvania
Contract Duration:	1992 - 1993

Indiana Gas Company; Cause No 39353

Client.	Office of Utility Consumer Counselor Indiana Government Center North 100 N. Senate Avenue, Room N501 Indianapolis, Indiana 46204 (317) 232-2494
Contact:	Robert Glennon
Assignment:	Review of the request of Indiana Gas Company to increase its rates and provide expert testimony on behalf of the Indiana Office of Utility Consumer Counselor. Issues addressed included· Weather normalized gas sales; the appropriate ratemaking treatment of an acquisition adjustment, intercompany allocations; collection charge revenues and changes in customer levels. In addition, we analyzed and presented testimony regarding the Company's proposal to include a weather "tracking" or weather normalization adjustment clause in residential and commercial space heating rates.
Key Participants:	Hugh Larkin, Jr.
Geographic Location·	Indianapolis, Indiana
Contract Duration:	May through August 1992

The Peoples Natural Gas Company; Docket No. R-00922180

Client: Pennsylvania Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
(717) 783-5048

Contact: Kent Murphy

Assignment: Larkin & Associates was retained by the Pennsylvania Office of Consumer Advocate to review the Peoples Natural Gas Company's application for an increase in rates. We presented direct and rebuttal testimony addressing such issues as: Construction Work in Progress, cash working capital, accounts payable related to materials and supplies, post-retirements benefits other than pensions, payroll expense, employee benefits expense, uncollectibles, Pilot Customer Assistance Plan expenses, outside services expense, injuries and damages expense, and relocation expense.

Key Participants: Ralph C. Smith

Geographic Location: Harrisburg, Pennsylvania

Contract Duration: 1992

Southern Union Gas Company

Client:	The Public Utility Regulation Board of The City of El Paso c/o Diamond, Rash, Gordon & Jackson 725 First City National Bank Building El Paso, Texas 79901 (915) 533-2277
Contact:	Norman Gordon
Assignment:	Review of gas Company revenue requirements and prefiled testimony addressing issues resulting from this review. Issues included: Acquisition adjustment amortization, investment tax credit amortization, liability insurance expense and acquisition investigation costs.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith
Geographic Location:	Austin, Texas
Contract Duration:	1991

United Cities Gas Company; Docket No. 176-717-U

Client.	Kansas Corporation Commission 1500 S.W. Arrowhead Road Topeka, Kansas 66604-4027 (913) 271-3200
Contact:	Dave Dittemore
Assignment:	Audit and review of utility rate increase request. Policy issues addressed included ratemaking treatment of an acquisition adjustment and non-compete agreement. Other issues addressed: pipeline safety deferrals, gas costs, employee benefits and distribution expense.
Key Participants:	Hugh Larkin, Jr.
Geographic Location:	Topeka, Kansas
Contract Duration:	1991

Southwest Gas Corporation; Docket No. U-1551-90-322

Client: Arizona Corporation Commission
1200 West Washington Street
Phoenix Arizona 85007
(602) 542-0745

Contact: Janice Alward

Assignment: Review of accounting and revenue requirements of gas utility. Prefiled testimony addressed the following issues: Prepayments, pipe replacement program, marketing and advertising expense, revenues, gain on disposition of property and officers' compensation.

Key Participants. Hugh Larkin, Jr.
Ralph C. Smith
Helmuth W. Schultz, III

Geographic Location. Arizona

Contract Duration: 1991

Southwest Gas Corporation - Purchased Gas Adjustment Report; Rebuttal; Docket Nos. U-1551-89-102; U-1551-89-103; and U-1551-91-069

Client:	Arizona Corporation Commission 1200 West Washington Street Phoenix, Arizona 85007 (602) 542-0745
Contact:	Janice Alward Chris Kempley
Assignment:	Larkin & Associates addressed certain issues and recommendations made in Southwest's prepared direct testimony. The following topics were addressed: Lost and Unaccounted for Gas; Adjustment to Account 191 for Tier-2 Gas Cost Corrections; Santa Fe Margin on System Gas sales to be Credited to Ratepayers; Allocation to Arizona of Santa Fe's Profits on End-User Sales.
Key Participants:	Hugh Larkin, Jr. Ralph C. Smith Helmuth W. Schultz, III
Geographic Location:	Arizona
Contract Duration.	1991

Equitable Gas Company; Docket No. R-901595

Client: Pennsylvania Public Utilities Commission
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
(717) 783-5048

Contact: Kent Murphy

Assignment: Rate base, operating income and revenue requirement issues including Company's capitalization of promotional allowances, projected plant additions, accumulated depreciation, materials and supplies, accounts payable related to CWIP, customer deposits, provision for rate refund, cash working capital (billing lag collection lag, other taxes lag, income tax lag, interest expense lag) residential sales, take-or-pay liability amortization, uncollectible, advertising & promotional expense, recoveries of theft of gas, association dues, employee retirements, projection of work force, pension expense, marketing study, energy assistance program, depreciation, gross receipts tax, customer deposit interest and income tax expense.

Key Participants: Ralph C. Smith

Geographic Location: Harrisburg

Contract Duration: 1990

Mountaineer Gas Company; Case No. 89-640-G-42T

Client: Consumer Advocate Division
West Virginia Public Service Commission
7th Floor, Union Building
723 Kanawha Boulevard, East
Charleston, West Virginia 25301
(304) 558-0526

Contact: Billy Jack Gregg

Assignment. Reviewed Company's rate base, including plant in service and accumulated depreciation, sale of liquid propane gas plant, plant acquisition from Columbia. Materials and supplies inventory; prepayments, including winter service and winter storage; working cash allowance; other rate base reductions, including customer deposits, accrued vacation pay, rate refunds, unclaimed accounts. Reviewed Company's operating income, including operating revenues; weather normalization, commercial and industrial sales growth. Miscellaneous revenue, including sale of liquid propane gas plant; operations and maintenance expense, including payroll, pension expense, uncollectibles expense, rate year P.S.C. expense, expense for mandatory drug/alcohol testing, legal and outside services expense, affiliated transactions, rate case expense, expense for lease of tape drives, truck lease expense, expense for electricity used by computer room, expense for rent-corporate office, inflation adjustment, EDP lease expense, advertising expense, computer software expense. Taxes other than income, including payroll taxes. Income taxes. Reviewed capital structure and rate of return.

Key Participants: Hugh Larkin, Jr.

Geographic Location: West Virginia

Contract Duration: 1989

Northern States Power Company - Gas; Docket No. G002/GR-86-160

Client: Office of the Attorney General
340 Bremer Tower
Minnesota Street at 7th Place
St. Paul, Minnesota 55101
(612) 297-4611

Contact: Dennis Ahlers
Curt Nelson

Assignment: Address impact of Tax Reform Act of 1986 on gas distribution utility operations including reduction in corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC and timing of TRA-associated impacts upon utility rates.

Key Participants: Hugh Larkin, Jr.
Ralph C. Smith

Geographic Location: Minnesota

Contract Duration: 1986-1987

Connecticut Natural Gas Corporation; Docket No. 87-01-03

Client:	Department of Public Utility Control - Prosecutorial Division State of Connecticut One Central Park Plaza Room 105 New Britain, Connecticut 06051 (203) 827-2603
Contact:	Steve Cadwallader William Darcey James Meehan
Assignment:	To determine the appropriate regulatory treatment associated with various changes in the tax code caused by tax reform and determine the impact of the Tax Reform Act on the cost of service and revenue requirements. Further, examine unbilled revenue, allowance for bad debt, inventory storage costs, cash flow changes associated with the TRA, excess accumulated deferred income tax reserve and adjustments to CNG's calculations.
Key Participants:	Hugh Larkin, Jr. Helmuth W. Schultz, III Ralph C. Smith
Geographic Location:	Connecticut
Contract Duration.	December 1986 - May 1987

AARON L. ROTHSCHILD
15 Lake Road
Ridgefield, CT 06877
Home: (203) 894-9628
Mobile. (203) 241-7824

EXPERIENCE

10/01- Present ROTHSCHILD FINANCIAL CONSULTING — **Wilton, CT**

Expert Witness

- Provide financial testimonies in support of utility rate regulation
- Developed ground breaking testimony supporting the use of a consolidated capital structure in the 2002 Verizon New Jersey rate case

2/01 – 7/01 360NETWORKS — **Hong Kong,China**

Senior Manager, Business Development

- Developed partnerships with telecom firms in Hong Kong, Singapore and Korea in order to gain facilities, adhere to regulatory requirements and expand sales efforts
- Evaluated the networks of our potential partners and negotiated pricing and other terms
- Recruited Business Development team in Hong Kong

7/00 – 1/01 DANTIS — **Chicago,IL**

Director, Business Planning

- Raised $100M from venture capital firm through valuation negotiations
- Worked with the Alliance group to identify facilities and marketing partnerships in Asia

MCI WORLDCOM — **Tokyo, Japan**

9/96 – 7/00 **Head of Business Development**

- Managed a team of Financial Analysts producing business plans in support of multimillion dollar funding requests
- Gained approval for a countrywide expansion plan in Japan
- Formed partnership with major credit card company to target 130K small to medium sized companies in Tokyo

Manager, Business Development — **Hong Kong, China**

- Managed development and presentation of capital justification business plans from Asia Pacific Headquarters
- Created a national expansion business plan for Japan with internet subsidiary UUNET
- Evaluated partnership with largest real-estate firm in Japan, including valuing an options grant program and presenting analysis to CEO of MCI WorldCom International

Analyst, Business Planning — **Chicago, IL**

- Managed business planning process for $30M to $100M phone/data network expansions
- Developed financial models to analyze local phone service investment opportunities
- Evaluated potential acquisition targets by valuing assets, customer base and synergies

EDUCATION

VANDERBILT UNIVERSITY — **Nashville, TN**
OWEN GRADUATE SCHOOL OF MANAGEMENT
Master of Business Administration, May 1996
Concentration in Finance

- Author and research assistant to statistics professor
- Intern at Nextlink Communications and Citizens Utility Board

CLARK UNIVERSITY — **Worcester, MA**
Bachelor of Arts, May 1994

- Peer tutor for mathematics department
- Captain of varsity baseball team

OTHER

- Columbia University, Part time student at School of Policy and International Affairs



Donna Mullinax
Vice President / CFO

Services
~ Regulatory Affairs
~ Rate Case Management
~ Executive Studies
~ Supply Chain Management

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Greenville, SC 29607
Office (864) 331-0700
Mobile (864) 420-8084
DMullinax@BlueRidgeCS com

Blue Ridge
Consulting Services, Inc.

December 3, 2004

RECEIVED
DEC - 6 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Illona A Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Re. Request for Proposal, Case No PU-04-578

Dear Ms. Jeffcoat-Sacco

Blue Ridge Consulting Services, Inc. ("Blue Ridge") is pleased to offer this proposal in response to the solicitation referenced above. We have enclosed one original and five copies of our proposal

Blue Ridge stands ready to accomplish the consulting engagement as detailed in the solicitation. Our proposal remains effective 90 days from the date of submission, December 6, 2004

Please contact me if you have any questions regarding anything in this proposal Thank you for your consideration.

Sincerely,

Donna Mullinax

Donna H Mullinax, CPA
Vice President/CFO

23 PU-04-578 Pages 30
Proposal
by Blue Ridge Consulting Services Inc.
12/06/2004 CC Comm Legal PUD (4) Mike

2131 Woodruff Road · Suite 2100 · PMB 309 · Greenville, South Carolina 29607
(864) 331-0700

RECEIVED
DEC - 6 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Proposal for:
North Dakota Public Service Commission
Request for Proposal, Case No. PU-04-578

Proposal Due: December 6, 2004

Prepared by:

Blue Ridge Consulting Services, Inc

In association with:

QSI consulting, inc

Donna H. Mullinax, CPA
Blue Ridge Consulting Services, Inc.
2131 Woodruff Road
Suite 2100, PMB 309
Greenville, SC 29607
Phone: (864) 331-0700
DMullinax@blueridgecs.com

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I. Introduction

On November 18, 2004, the North Dakota Public Service Commission extended a Request for Proposal (RFP) for Case No PU-04-578 to assist Commission Staff in its investigation of Northern States Power Company's gas rate increase request.

In response, Blue Ridge Consulting Services, Inc is pleased to submit this proposal for to the Commission for its review and consideration We intend to achieve two primary goals through this response to the RFP First, we will demonstrate our understanding of the scope of services requested by describing the tasks, inputs, outputs, and interrelationships among the tasks that may develop throughout the engagement Secondly, we will demonstrate the benefits that our unique combined experience provides to the Commission and its Staff

The contact person for purposes of responding to any inquiries you may have is

Donna H. Mullinax, CPA
Vice President / CFO
Blue Ridge Consulting Services, Inc.
2131 Woodruff Road, Suite 2100
Greenville, SC 29607
Office. (864) 331-0700
Email: dmullinax@blueridgecs.com

II. Executive Summary

Blue Ridge Consulting Services, Inc (Blue Ridge) in association with QSI Consulting, Inc. (QSI) is pleased to submit this proposal to the North Dakota Public Service Commission (Commission) for its review and consideration. We have assembled an outstanding team of experienced utility consultants and analysts to be able to meet and exceed the expectations that the Commission has for this solicitation as we assist Commission Staff in its evaluation of Northern States Power Company's (NSP's) gas rate increase request.

The Blue Ridge team includes consultants that provide specific complementary experience and subject matter expertise in rate base, costs of capital, cost of service, regulated net income and rate design. Our team includes individuals that have worked for and with state and federal regulatory agencies, utility holding companies and their regulated and non-regulated affiliates, non-utility energy service providers, and energy consumers The diverse practical experience of the Blue Ridge team will bring a unique perspective to this rate case

With over 100 years of operational and financial utility management experience, the Blue Ridge team has both the breadth and depth of experience to be an effective advocate for the Commission in the NSP rate case We have the requisite experience and skills to be able to analyze the operations, books and records of utility companies for the purpose of setting just and reasonable rates and are qualified and prepared to render expert testimony

We have a proven track record of winning our respective positions before utility commissions and are ready to provide that same level of service to the Commission and its Staff We have proposed a small, yet highly experienced team of rate case professionals whose combined experience covers every aspect of the rate case process

In addition to being highly qualified to perform the services requested in the RFP, the majority of the outstanding shares of Blue Ridge are women owned and we are pursuing certification as a women-owned business Selecting Blue Ridge will continue to demonstrate the Commission's commitment to support small and women owned businesses.

The goal of this proposal is to clearly demonstrate our understanding of the Statement of Work and identify the activities, inputs, outputs and interrelationships among the task assignments that may develop throughout the engagement Our approach follows a methodology, which leverages our understanding of the regulatory process. As outlined in the solicitation, the Blue Ridge team will perform the following major tasks.

1 Professional analysis and review of the filing.
2 Prepare and conduct discovery as necessary
3. Monthly progress reports of discovery, conclusions and recommendations

4. Prepare and file written testimony.
5 Provide oral testimony.
6 Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding
7 Assist staff in the preparation of proposed findings of fact

The major tasks above may generate the following activities.

- Review filing for major rate and revenue requirement impacts proposed by the Company
- Compare income statements from previous cases – note major changes
- Review and compare rate base, O&M, cost of service studies from previous to current case
- Track and trend revenue erosion since the last rate case
- Review and evaluate the cost of capital issues
- Review present and past rate design and tariffs by examination of current and past rate schedules
- Prepare interrogatories for submission to the utility and all intervening parties. (This step is repeated for rebuttal and surrebuttal – if necessary)
- Calculate revenue requirement based on testimony, exhibits, and responses to interrogatory requests
- Review the Company's fully allocated cost of service study, including all allocators, to determine relative rate of return by class and intra-class rate design issues
- Review the Company's Tariff and included rate schedules to determine its impact on cost of service and rate design
- Determine if any industry competition/re-structuring issues need to be reviewed
- Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding, including supporting "mock-cross" with Staff
- Prepare and file written testimony
- Provide oral testimony
- Monitor and participate in hearings
- Assist staff in the preparation of proposed findings of fact
- Review and prepare summary memo on issues
- Work closely with Staff to submit briefs and brief on exceptions

We have also provided a Quality Assurance process that includes our team based, peer review process. This process can be found in Appendix 1 We believe that our process ensures that the work products and deliverables will exceed all of the quality standards that the Commission expects from the contractor awarded this project

As the Commission is aware, the rate case process is dynamic and highly variable As issues unfold new insights and research is needed to adequately prepare a position that is in the best interest of the ratepayers

Blue Ridge is prepared to offer the Commission a firm fixed price, not to exceed cost for professional fees and expenses of $83,205 00 including travel and out of pocket expense) for the contract for all activities related to Case No. PU-04-578

III. Blue Ridge Experience

Blue Ridge brings extensive background knowledge, best practices, skills, and experience to exceed the Commission's expectations We have a history winning the issues that we propose Collectively, the Blue Ridge team members have provided expert testimony in several states and jurisdictions

The most significant and relevant experience to the Statement of Work in this solicitation includes the number and breath of rate cases that the team has worked on throughout their individual careers These cases include.

- District of Columbia Public Service Commission – advised the Commission on the reasonableness of dozens of pro forma adjustments proposed by Washington Gas Light Company (WGL) in case FC1016. Based on our analysis, the Commission reduced the proposed increase in revenue requirements by 2/3rds The project included an in-depth assessment of the WGL's proposed changes in depreciation rates and methodologies.
- Illinois Power Company – Delivery Service Tariff filing (Docket No 99-0134 and 01-0432)
- Long Island Lighting Company show cause proceeding to effect immediate rate relief to rate payers
- Atlantic City Electric Company – numerous cases covering revenue requirements, rate design, cost allocation, PURPA lifeline & rate design, capacity planning, line extension policies, independent power contracts, load forecasting, certificate of need and transmission line siting.
- One member is involved in a major Midwest utility's gas rate case that is pending before its State Regulatory Commission Activities include development of an asset separation analysis designed to allocate common facilities and plant investment to the company's lines of business and business segments, development of a forecasted capital additions forecast and updates which put forth the estimated additions, retirements and cost of removal components, development and review of related pro forma adjustments; preparation of responses to discovery, testimony support, and other related activities.

Additional regulatory / consulting assignments have included.

- Testified in a prudence proceeding against a major New York utility for improperly spending over $125 million on an unproven coal cleaning technology Settlement negotiations led to ratepayers receiving $66 million over five years
- Conducted an audit of a major mid-western electric utility's wholesale energy transactions and the accountability of the tens of thousands transactions that move through the company's books One member of the Blue Ridge team testified to and the Commission accepted an audit approach which will allow for greater accountability in that process

- Reviewed, evaluated and recommended enhancements to the trading practices associated with regulated utility in the utility's $1 4 billion wholesale energy market for the Colorado Public Utility Commission
- Prepared required analyses, filings and testimony for Illinois Power Company's compliance with the State of Illinois' mandatory separation of the generation, transmission and distribution functions as the State de-regulated
- Advised a state senator on the proper procedure and process for requesting that the utility commission conduct a management audit of a utility's distribution plant maintenance practices and procedures.
- Allied a client's position with industrial interveners to retain a declining block rate that had been specifically designed to build load factor and increase off-peak usage The alliance was successful in retaining this rate form which encouraged efficient use of utility facilities and energy
- Developed, implemented and successfully defended a line extension policy designed to protect existing customers from speculative high marginal cost service requests
- Convinced a regulatory staff that affected property owners, municipal officials and general public that a proposed transmission line route had been given timely, relevant and sufficient information regarding the impact of the transmission line such that the proposed route was approved
- Successfully presented analysis and evidence to support a definitional change in a regulatory commission's standard for "known and measurable" for projected/forecasted capital additions
- Successfully defended company's position to retain construction deposit funds for a major line extension project when the developer cancelled the project that would be served by the line extension
- Testified as to the prudence and public interest findings related to several nuclear power plants in Texas
- Testified as to whether or not the merger of Gulf States Utilities and Entergy was in the public interest

The team has revenue requirement development experience and has worked with clients to establish revenue requirements based on testimony and exhibits presented in testimony Given the diverse nature of the rate case process from jurisdiction to jurisdiction, our team has the experience necessary to generate (if not already available at the PSC) an effective computerized model, which links all of the various schedules and correctly calculates the revenue requirement according to procedures and precedents determined by the Commission

Blue Ridge's team has testified before a number of regulatory authorities on behalf their clients Our team has testified to

Rate Base	Generation and Transmission Siting	Load Research
Rate of Return		Cost Allocation
O&M	Specialized Line Extensions	Cost of Service
Prudency Reviews	Power Contracts	Rate Design
Load Forecasting	Operational Efficiency	Rate Schedules
Capacity Planning	Wholesale Energy Trading	Billing Determinants
Conservation Programs	Cost of Capital	Tariff Issues (non rate)
Demand Side Management	Transfer Pricing	Valuation Studies
	Cost Sharing Studies	

References

The Blue Ridge team members are experienced professionals with long and successful careers in assisting their clients This experience provides the Commission with the assurances that the key members of our team have the skills required to successfully complete this project. The following recent references are provided for our senior team members.

Donna H. Mullinax, CPA
Washington Gas & Light Rate Case
Docket FC1016 (Aug'03 to Jan, '04)
Client District of Columbia Department of Public Service
Contact. Mr. Dwayne T Boyd (retired)
301- 929-1904

Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (01/04-11/04)
Docket No 04A-050E
Client. COPUC
Contact· Geri Santos-Rach
303-894-2533

Michael McGarry, Sr
Washington Gas & Light Rate Case
Docket FC1016 (Aug'03 to Jan, '04)
Client. District of Columbia Department of Public Service
Contact: Mr. Dwayne T. Boyd (retired)
301-929-1904

Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (01/04-11/04)
Docket No. 04A-050E
Client COPUC
Contact. Saeed G Barhaghi, PE
303-894-2871

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KPMG
Contact. Dr. A E Rodriguez
Associate Professor
Department of Economics and Finance
School of Business
University of New Haven (CT)
Tel· 203-932-7372
arodriguez@newhaven edu

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Daniel Roethemeyer
Dynegy Midwest Generation
2828 N Monroe Street
Decatur, IL 62526
Phone. (217) 872-2309
E-mail: Dan_Roethemeyer@dynegy.com

IV. Project Team

Blue Ridge is a women-owned small business located in Greenville, South Carolina. We have served a wide range of clients during our principals' more than 35 years of experience including regulatory commissions, utilities, their affiliates and suppliers Additionally, we have worked with a wide range of commercial and industrial customers

Our consulting practice has evolved into several of distinct areas:

- Regulatory support and intervention, including testimony, rate base determinations and cost of service
- Management consulting, including management and operational auditing, process review, implementation planning and monitoring

The hallmark of our consulting practice is our ability to deliver comprehensive results on a timely basis To that end, we carefully plan our consulting engagements and select only experienced team members Our approach ensures that our clients receive the most cost effective solution and not bear the cost of educating less experienced consultants that many larger firms assign to projects We have the flexibility to adapt to changing circumstances that may result from the rate case proceedings before the Commission. Our team is thorough, reliable and most importantly will develop positions that are defendable.

In order to provide the highest quality and experience level to satisfy the Commission's request in this solicitation, Blue Ridge has teamed with experienced consultants and subject matter experts Our team collectively bring over 100 years of utility related experience covering every area of utility management, operations, finance, accounting, rate case management and regulatory affairs Members of the Blue Ridge team have testified in regulatory proceedings before the New York State Public Service Commission, the Illinois Commerce Commission, the New Jersey Board of Public Utilities, the Maryland Public Service Commission, Public Utilities Commission of Texas, and the Colorado Public Service Commission to name a few of the several state agencies that our team members collectively have provided expert testimony All have prepared testimony on behalf of clients or senior managers in support of positions that were beneficial to their respective clients or employers.

Members of the senior team have graduate degrees representing the engineering, business administration, economics, and general management disciplines The team consists of two certified public accountants, a Ph D in economics, and a professional engineer. Most have utility management and significant rate case management experience.

Included as Appendix 2 are the resumes of the team, which provide greater detail into the specific experience that the team has performed for their respective clients and companies

Team Organization and Personnel Assignments

In addition to its own professionals, the Blue Ridge team includes contract consultants that provide specific complementary experience and subject matter expertise. By mutual agreement, each member of the team is contractually committed to provide the expert consulting services needed to fulfill Blue Ridge's obligation under this solicitation This contractual commitment is stronger and more stable than an employee-employer relationship and therefore the Commission will have a more efficient team over the term of this contract.

Blue Ridge has selected a team that is very capable of providing the range of services and a strong bench to ensure that the rate case is effectively and efficiently managed and the revenue requirements and associated analyses are delivered on time, accurately and completely Our project management methodology has been designed to judiciously work on the development of revenue requirements, cost of service, rate design and cost of capital and assessment of accounting related issues in the case that the Commission requires

In an effort to assist the Commission and Staff with its evaluation of our capabilities and demonstrate both the breadth and depth of experience to satisfy what we believe the Commission's requirements would be for this engagement, we have prepared a Task Matrix (See Appendix 3). This matrix shows how each member of the team has a tremendous cross-functional capability in rate case management, utility studies and quality oversight. Members of the team complement one another with their knowledge, skills and abilities

Team Roles and Assignments

Our expert team is composed of only senior level professionals who each have over twenty years of relevant experience. Our proposal incorporates the concept that it is likely that a number of interventions and/or utility negotiations could be on going at the same time Therefore, we have positioned the team to accommodate that likelihood As described in the Task Matrix in Appendix 3, our team brings complementary and overlapping skills that allow us to propose this approach

Project Manager – Testifying Witness

Donna H. Mullinax, CPA, will serve as the lead for the engagement. She will be responsible for managing the day-to-day activities of the team and be the liaison with the Commission's Rate Case Project Manager and Lead Attorney Mrs Mullinax is Vice President and CFO with Blue Ridge

Mrs. Mullinax has over twenty-four years of financial, management and consulting experience. She has extensive project management and experience in economic viability studies, due diligence reviews, and litigation support She has been involved in cost prudence reviews, economic viability studies, system implementation and audits She recently testified before the Colorado Public Utilities Commission to the findings of

a transaction audit of PSCo's electric commodity trading operations In addition, Mrs. Mullinax led the review of WGL's depreciation study and proposed rates and provided recommendations to the District of Columbia Public Service Commission on the company's proposal in FC1016

She has worked with expert witnesses to draft pre-filed testimony of actual findings and calculated damages, and she has developed questions and answers to support counsel during depositions and trial

Senior Technical Consultant – Testifying Witness

Michael J. McGarry, Sr. will provide subject matter expertise on an as needed bases including providing the peer review of work product developed during this project Mr. McGarry has testified (or prepared testimony) in a number of jurisdictions He is knowledgeable and well versed in the issues facing the energy industry with respect to deregulation, cost unbundling, rate case management and regulatory affairs. He has advised clients on how to best implement regulatory and legislative mandates in the area of restructuring

Mr McGarry is President of Blue Ridge Consulting Services, Inc Regulatory affairs projects have included assisting with and managing a rate case management project for Commissions, a major mid-west electric and gas utility, and working as a special advisor to a State Senator on a the effectiveness of a storm restoration and preventative maintenance program for a major southern utility.

Mr McGarry's regulatory career spans more than twenty-three years and includes work as a rate analyst, operational and management auditor and senior consultant. He has worked for firms such as Orange and Rockland Utilities, Inc. and Seminole Electric Cooperative, Inc In 1985, Mr. McGarry joined the NYS Dept of Public Service as a Utility Operational Examiner where he conducted over twenty management and operational audits covering numerous topics He also testified in a number of prudence reviews and two rate filings

Mr McGarry began his consulting career in 1997. In his capacity as a management consultant, he was responsible for providing analytical skills in management audits, supply chain project and rate cases including the Delivery Service Tariff filing in Illinois in 1999 and again in 2001. Mr McGarry has developed the management and analytical skills for supporting all aspects of evaluating rate base, operation and maintenance expenses, revenue requirements, preparing and defending expert testimony and advising Commissioners on the appropriateness of most facets of a utility's revenue requirement

Senior Technical Consultant – Testifying Witness

Dr. Jeffrey I. Rosenblum will serve as lead for all work related to cost of capital Dr Jeffrey I. Rosenblum is the founder and President of Monrosen, Inc , an economic consulting company In addition to his experience as a utility economist and expert witness, Dr Rosenblum has extensive knowledge of international transfer pricing,

industrial organization, applied microeconomic theory, and a broad range of issues relating to law and economics He has provided expert witness testimony on behalf of AT&T, MCI, and other telecommunications carriers in various state jurisdictions and before the Federal Communications Commission

Since 1994, Dr Rosenblum has been involved in the area of international transfer pricing, first for KPMG LLP and later for Arthur Andersen LLP In this capacity, his clients have included financial services firms (including French, German, and Canadian banks and various brokerages), pharmaceutical firms, chemical and food manufacturers, Japanese trading companies, Mexican maquiladoras, distributors of all types and miscellaneous service providers He has undertaken cost sharing and profit split studies and many studies testing inter-company royalty rates, including several for state and local tax purposes. Dr. Rosenblum has also applied his knowledge of economics and utility regulation in valuation studies and for utility clients in Panama in Aruba

Prior to his involvement in transfer pricing, Dr Rosenblum worked as an expert witness for eight years at the Public Utility Commission of Texas, where his responsibilities included litigation support, the design of electric utility rate structures, cost analysis and allocation, econometric forecasting, and participation in various rule-makings. The dockets in which he has testified include the request of Houston Lighting and Power to swap its ownership share in the South Texas Nuclear Project with the City of Austin, the prudence of TU Electric's buyback of capacity in the Comanche Peak Nuclear Generating Station, the prudence of El Paso Electric Company's decision to participate in the Palo Verde Nuclear Generating Station, and numerous other dockets involving rate design, forecasting, and other regulatory issues Dr. Rosenblum was also the Commission Staff's lead witness in the Gulf States Utilities merger with Entergy.

Senior Technical Consultant – Testifying Witness

Howard Solganick, P.E. will serve as lead for all work related to cost of service, rate design and tariff policies and procedures (if applicable). Mr. Solganick is the founder of Energy Tactics & Services, Inc., which has served the energy industry since 1994. He started his energy career with Atlantic Electric (now part of PEPCO) where he had a wide range of assignments in generation, power supply, rates and regulation, customer service, corporate planning and corporate performance During his tenure with Atlantic Electric, Mr. Solganick was responsible for the negotiation of major service agreements with DuPont and Mobil, and major power supply agreements with five independent power producers for a total value of over eight billion dollars.

Mr. Solganick appeared as a witness on rate design, cost allocation, load forecasting (including weather adjustments), demand side management, construction and other customer issues before the Office of Administrative Law and hearings chaired directly by the Commissioners of the Board of Public Utilities ("BPU"). He was directly responsible for cost of service studies and rate design, customer load research, saturation studies and tariff management and implementation. He was responsible for establishing new rate schedules and revising existing schedules to reflect evolving needs such as demand side incentives and line extension policies In addition, he acted

as the primary utility coordinator for the first management audit performed by the BPU under the establishing legislation.

As president of an independent power producers trade association, he led a regulatory intervention in Maryland to open the wholesale marketplace to competition. Mr. Solganick acted as the expert witness in the case, which resulted in a competitive procurement order by the Commission He also served as a member (IPP) of the New Jersey Board of Public Utilities' Advisory Council on Electric Utility Planning and Procurement, chaired by Commissioner Carmen J Armenti

After four years with an independent power producer, he was a managing consultant with *jamesmartin+co* and AT&T Solutions where he concentrated on engagements that enhanced the relationship between utilities (and energy retailers) and their customers

In his management consulting practice, Mr. Solganick has worked with a number of recently formed, expanded or reorganized holding companies and has explored issues such as management, economies of scale, organization development and unregulated affiliates.

Mr Solganick has structured a number of competitive procurements for commodity energy. Additionally, he has consulted a number of energy retailers as they explored and implemented retail ventures for residential and commercial customers When combined with his regulated rate design experience he brings a broad view of retail customer knowledge to the rate design process

Senior Technical Consultant - Testifying Witness

Michael T. Dryjanski, CPA, will work on the engagement as a Senior Technical Consultant and will focus on depreciation, rate base and revenue requirements. Mr. Dryjanski is president of MTD Consulting and Services, Inc He specializes in utility rate making proceedings, depreciation studies and litigation support He recently was the key expert on the WGL rate case (FC1016) where he conducted an in-depth assessment of the Company's proposed changes in depreciation rates and methodologies. He advised the Commission on a number of the issues including amortization accounting

Mr Dryjanski is currently supporting a gas rate case engagement for a major Midwest utility. This docketed case is pending before its State Regulatory Commission His primary focus in this engagement is the company's historical rate base, forecasted changes to rate base, related pro forma adjustments, testimony support and discovery

In his career, Mr Dryjanski has held a variety of accounting supervisory and management positions at Illinois Power Company such as Supervisor of Project Controls at the Company's nuclear power plant, Director – Property Accounting and Payroll and as Business Leader responsible for Capital Asset Accounting.

In his various roles, Mr Dryjanski has provided material support in various electric and gas regulatory proceedings before the Illinois Commerce Commission (ICC) for Illinois

Power Some of the ICC dockets that he supported include Dockets Nos 91-0147, 92-0465, and 93-0183. His activities included the development of documentation and analysis of major capital projects, testimony preparation and witness support, electric and gas depreciation studies and related accrual rates, rate base development and issue analysis and response, as well as other supporting activities

He developed a functional asset separation cost study that was submitted in testimony in ICC Docket 98-0860 as well as provided the related written and verbal testimony before the Illinois Commerce Commission (ICC) This study became the basis of an administrative and general expense (A&G) cost allocation study that was submitted in the same docket Data developed from this project was also integrated into the Company's Open Access Transmission Tariff (OATT) filing before the FERC.

Mr. Dryjanski has been instrumental in determining the allocation of cost of wholesale distribution facilities for delivery points of wholesale customers pursuant to Docket ER99-4415.

In ICC Docket 01-0432, he co-developed post-test year plant additions in the Company's most recent Delivery Service Tariff case which resulted in definitional change of "known and measurable" and allowed for planned expenditure reflection in the determination of total rate base.

Consultant

Debra Rollins is a consultant with Blue Ridge Consulting Services, Inc. and will support the team in pro forma analysis and document management Ms. Rollins has assisted the Blue Ridge team on numerous consultant projects including tracking and trending energy segments with focus on nuclear, assisting in document management production for legal projects, litigation support, and other rate cases including discovery, hearings and deliberation

Ms. Rollins has over twelve years of professional experience in the areas of internet management, project management, financial projects, logistics, training and human resources. Ms. Rollins has served as a Logistics Engineer for both the lead logistics provider to a premier automotive manufacturer and global leader in supply chain and transportation management solutions Ms. Rollins has been responsible for operational design, warehouse layout, material flow, process flow / improvement, and supplier trouble shooting Her experience includes the preparation of time studies, cost analysis, route optimization, site selection, facility design, layout design, statistical analysis, load planning and scheduling.

V. Work Plan

Introduction

As stated in the solicitation, the Commission is seeking a consultant to investigate, analyze and provide testimony regarding the fairness and reasonableness of NSP's proposed rate base, cost of capital, regulated net income and rate design. The purpose of this response is to demonstrate Blue Ridge's understanding of the consulting duties requested by the Commission The Request for Proposal has defined those specific duties to include·

1 Professional analysis and review of the filing
2 Prepare and conduct discovery as necessary
3 Monthly progress reports of discovery, conclusions and recommendations
4. Prepare and file written testimony
5. Provide oral testimony
6 Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding
7 Assist staff in the preparation of proposed findings of fact

Our technical approach and methodology for successfully achieving the objectives the Commission has for this project are described below

Approach

Blue Ridge uses an effective approach to provide the specific expertise needed to satisfy the requirements of this Request for Proposal and meet the Commission's requirements. We have proposed a small, yet highly experienced team of rate case professionals whose combined experience covers every aspect of the rate case process

We have also provided for a Quality Assurance process that includes our team based, peer review process This process is fully described in Appendix 1. We believe that our process ensures that the work products and deliverables will exceed the quality standards that the Commission and Staff expect from its consultant

Methodology

In this section we will present our technical understanding of the activities, inputs, outputs and interrelationships of the tasks and activities associated with the rate case process

The utility regulatory proceeding process, or rate case, requires a pro-active approach in order to be effective. The process serves as a surrogate for a competitive market where true competition exists Utility companies have long held monopoly positions and as such require regulatory oversight to ensure the rates they charge consumers are fair

and reasonable The rate case is an administrative legal process whereby the utility must prove that its rates are fair and reasonable

Blue Ridge and its team of consultants bring superior utility regulatory proceeding experience to this engagement The following discussion will demonstrate our technical understanding of the specific tasks and assignments that could develop out of this engagement

Rate Base

NSP proposes an increase to its rate base to recover the costs of expanding, upgrading, operating and maintaining the Company's natural gas distribution system in the state's two largest communities

The Blue Ridge team anticipates that our assistance to the Commission and Staff in analyzing the rate base component will consist of providing evaluations and recommendations in the following

1. Consistency and appropriateness of the direct assignment and allocation of plant investment for jurisdictional rate base development and the related allocators

2 The additional investment is in service prior to the rates going into effect

3. Review depreciation rates used for the new investment to ensure that the depreciation rate in use have been approved by the Commission

4. Review the treatment of Construction Work in Progress (CWIP) and Allowance for Funds used during Construction (AFUDC) to determine whether they are in compliance with the Commission's policies and precedence.

5 Analyze the impact of the Company's proposal to include the unamortized environmental clean-up costs of the former site of a manufactured gas plant (approximately $1 8 million) in rate base

Cost of Capital

In NSP's *Notice of Change in Rates for Natural Gas Services* filed on November 2, 2004, the Company does not propose an increase in return on equity for its North Dakota gas operations The Company has used 11 5 percent for its return on equity in its application, the same return on equity used by the Commission to set final rates in NSP's 2000 natural gas rate case The fairness and reasonableness of continuing to use the same return on equity should be analyzed

The Blue Ridge team anticipates that our assistance to the Commission and Staff in analyzing the cost of capital component of its revenue requirement calculation will consist of providing evaluations and recommendations in the following areas.

1. Calculation of NSP's costs of debt and preferred stock.

2 Determination of the appropriate capital structure

3 Review the Company's proposed 11 5% cost of equity Analyze and if necessary, challenge the modeling assumptions used to develop this rate If the Company has simply plugged this rate from its 2000 rate case, we will need to consider carefully whether the assumptions used to develop this rate in 2000 are still applicable and continue to result in an overall cost of capital that is consistent with allowing the Company an opportunity to earn a fair and reasonable return on its investments.

The Blue Ridge team also anticipates providing assistance to the Commission and Staff in the development and use of spreadsheets models to facilitate the calculation of various cost of capital components, as well as the overall weighted average cost of capital, under different assumptions.

Revenue Requirements and Regulated Net Income

An integral part of the process is the determination of revenue requirement or that amount of money that the utility will be allowed to collect through it rates from its ratepayers This revenue requirement allows the utility to collect those costs it needs to operate and earn a fair return for its shareholders.

The following table illustrates a typical revenue requirements calculation

Example of Revenue Requirement Calculation

		Adjusted Jurisdictional DST
Rate Base ($000)	$	909,162 80
Times Before Tax Weighted Cost of Capital		8 92%
Authorized Return (on Equity) ($000)	$	81,097 00
Amortization of ITC	$	572 99
Taxes on Interest Synchronization Deduction	$	15,205 19
After Tax Rate Base Return Requirement	$	65,318 82
Gross Conversion Factor		1 664308896
Authorized Return Grossed Up for Taxes	$	108,711 00
Operating Expenses before Income Taxes	$	190,719 31
Revenue Requirement ($000)	$	299,430 31

Not shown in this calculation are the dozens of schedules that support the development of this summary table They include schedules supporting rate base, determination of cost of capital, taxes and operating expenses Provided in Appendix 4 are examples of the schedules that support the determination of rate base and operating expenses before income taxes If selected, we can provide the Commission and its Staff the same level of expertise in developing the specific schedules using MS-Excel that will accurately calculate the revenue requirement in the current case It will allow for "what-if" scenario analysis as adjustments are proposed by Staff or the Interveners

NSP's filing states that Xcel Energy has been able to "hold its operating and maintenance costs flat compared to the time of its last rate case in 2000" The Company further states that the requested increase is driven primarily by investment related costs associated with meeting growth in its service territory and the revenue erosion caused by declining use per customer We will evaluate whether these statements are true and correct and what impact, if any, any discrepancies have on revenue requirement.

Cost of Service and Rate Design

Blue Ridge has tremendous experience in cost of service and rate design. Some of the issues that may need to be addressed during this proceeding are discussed in the following paragraphs Blue Ridge stands ready to assist in any and all of these areas

Just as the Commission makes a determination that revenue requirements are just and reasonable for the jurisdictional utility and its stockholders by considering rate base, expenses, rate of return and other factors, the Commission should perform a parallel investigation for each customer (or rate) class A fully allocated cost of service study allows the Commission to determine the fairness of the contribution of each customer class Without a fully allocated cost of service study the fairness of the utility's rates to individual customer classes cannot be confirmed. Blue Ridge will analyze the cost of service study performed by the Company

The fully allocated cost of service study attempts to measure the relative position of each customer class and compare that with the utility itself A fully allocated cost of service study will provide relative rates of return for each customer class The Commission can use that information to determine whether each customer class should have similar rates of return or if they should vary based upon issues such as class risk, prior rate structures or levels, social or economic impact, or other quantitative or qualitative factors For example, if the Commission determines that the relative rates of return should be equal it should consider over what time period (or number of rate cases) it would require the Company make that change if warranted (phasing).

The fully allocated cost of service process is well defined, however, the cost of service practitioner has some discretionary leeway that can affect the results of a cost of service study The Company's inputs into functionalization, classification and allocation must be examined to determine if any bias existed Reasonable practitioners can disagree among potential theories, however the decision on the applicable theory and its application is made by the Commission

Utilities that span multiple jurisdictions present a special case. Jurisdictional issues require deference to the FERC but also a careful examination by the Commission In a utility that is part of a larger group, jurisdictional issues become more important and must be examined as they may not have existed in past cases Specific issues that may not have FERC guidance include allocation of senior executive time, sharing of information technology costs and benefits, efficiency of planning functions and opportunities to share or duplicate resources

The Company's policies and procedures can also impact the cost of service study. For example, if the credit and collections policies are different between customer classes then simple customer or revenue driven allocators may be inappropriate

Cost allocation may change over time due to changes in economic, social and other factors. For example, over time appliances have become more efficient and the usage characteristics that impact volume have changed Rates set years ago may still provide the Company with a fair rate of return but may be penalizing some customers and undercharging others

After the Commission has investigated cost of service in detail, rate design comes to the forefront Rate design is best described as intra-class while cost of service is interclass Many rate design issues can be explored using an in-depth form of the fully allocated cost of service model. The Commission also can direct the rate design practitioners to include or consider non-cost based issues. These issues may be included to protect a sub class of customers from an adverse (major or rapid rate change) or to encourage certain behaviors or economic patterns such as increasing end use efficiency.

When done appropriately rate design can also inform customers about the cost of service For example, fixed or minimum service charges that include a baseline amount may distort the customer's perception of the cost of meter reading, billing and customer service Seasonal rates may send messages about not only varying gas purchased costs, but also the seasonal costs of transmission and distribution

Cost of service and rate design even extends to miscellaneous charges such as connections, disconnections, special meter readings and other customer requested services A proper coordination of charges and policies and procedures can reduce the cost of service for all customers by reducing the frequency of these services Higher rates may provide a decrease in revenue due to fewer service requests which subsequently reduce costs overall potentially

The key to efficiently reviewing individual customer rates is the appropriate integration of revenue requirements and the cost of service process. Without this linkage the rate case can be delayed The fully allocated cost of service study should proceed in parallel with the revenue requirements process and be appropriately linked The cost of service model should be able to rapidly allocate any and all adjustments being considered during the revenue requirements phase to provide a near real time impact analysis for each customer class In most cases an adjustment proposed will use the same cost allocator as the underlying rate base or expense issue; however, the cost of

service model should allow the use of more appropriate allocators if needed. Blue Ridge has the capability to link its revenue requirements and fully allocated cost of service models to provide a near real time response to the Commission

Preliminary Work Plan

Blue Ridge has included a preliminary work plan to complete the scope of work for this project Upon award of the contract with the Commission, we will provide a final version for Staff's review and approval

A typical work plan for a full rate case would likely include the following tasks:

- Review filing for major rate and revenue requirement impacts proposed by the Company
- Compare income statements from previous cases – note major changes
- Review and compare rate base, O&M, cost of service studies from previous to current case
- Track and trend revenue erosion since the last rate case
- Review and evaluate the cost of capital issues
- Review present and past rate design and tariffs by examination of current and past rate schedules
- Prepare interrogatories for submission to the utility and all intervening parties. (This step is repeated for rebuttal and surrebuttal – if necessary)
- Calculate revenue requirement based on testimony, exhibits, and responses to interrogatory requests
- Review the Company's fully allocated cost of service study, including all allocators, to determine relative rate of return by class and intra-class rate design issues
- Review the Company's Tariff and included rate schedules to determine its impact on cost of service and rate design
- Determine if any industry competition/re-structuring issues need to be reviewed
- Assist staff in preparing cross-examination of the witnesses of other parties to the proceeding, including supporting "mock-cross" with Staff
- Prepare and file written testimony
- Provide oral testimony
- Monitor and participate in hearings.
- Assist staff in the preparation of proposed findings of fact
- Review and prepare summary memo on issues
- Work closely with Staff to submit briefs and brief on exceptions

Progress Reporting

Blue Ridge will provide the Commission with informal weekly status reports in a form of the Commission's choosing (email, phone call, or short report). The status report will

include a review of the previous week's activities and accomplishments, as well as a schedule of anticipated tasks and activities including any projected travel

Monthly progress reports of discovery, conclusions and recommendations will be provided on the first of each month This report will provide specifics on the progress of individual tasks and assignments, expected tasks to complete in the upcoming month, major milestones achieved and anticipated, and a review of the project costs (both incurred and projected) This information will be provided in an agreed-to format

We will track our progress against our work plan Should a new issue emerge, we will adjust the work plan or develop a new work plan to address the emergent issue.

Document Management

In order to be effective in the rate case process, it is essential to track and manage the tremendous amount of information that is generated in the process Blue Ridge uses a computerized tracking relational data base that assists with the interrogatory process which allows us to analyze information across issues, parties and witnesses It also allows us to ensure that all interrogatories are answered in a timely fashion. This tool has been invaluable in helping clients ensure that they are getting the information they need to support their case

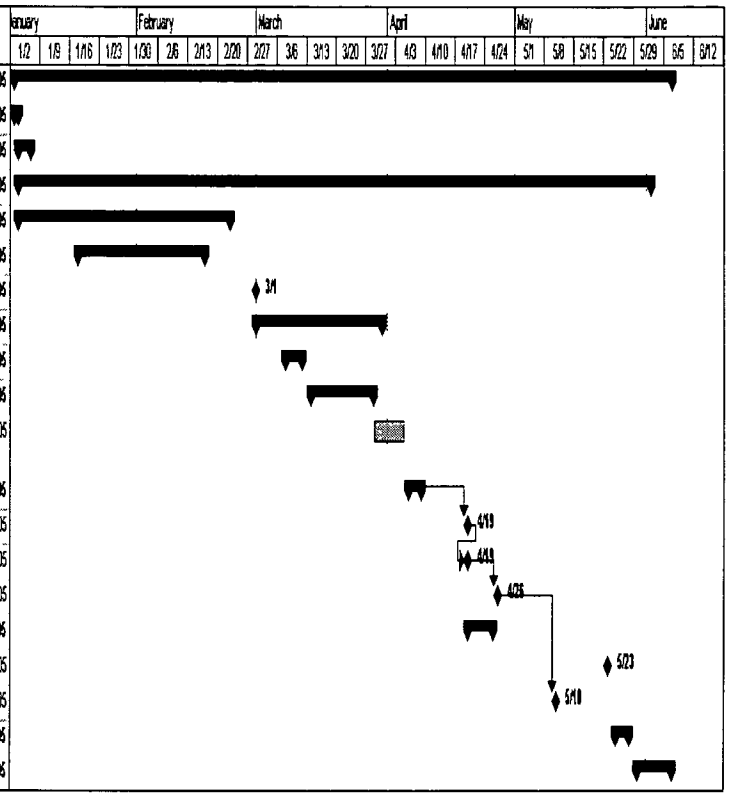
Project Schedule

Blue Ridge understands that the completion date for the investigation and written testimony is March 1, 2005. The technical hearings will be scheduled for mid to late April 2005 The Gantt Chart on the following page illustrates the major tasks and activities discussed in this proposal and how they interrelate for successful completion Blue Ridge is flexible and will modify this schedule and its work efforts to whatever the Commission's directives.

A detailed version which list all significant tasks and activities is included in Appendix 5

Figure 1 – Illustrative Project Schedule

ID	Task Name	Duration	Start	Finish
1	NSP Rate Case (PU-04-578)	110 days	Mon 1/3/05	Mon 6/6/05
2	Contract Award	1 day	Mon 1/3/05	Mon 1/3/05
4	Finalize workplan with Staff	3 days	Tue 1/4/05	Thu 1/6/05
5	Project Management	106 days	Tue 1/4/05	Wed 6/1/05
14	Discovery	36 days	Tue 1/4/05	Tue 2/22/05
18	NSP Primary Case Analysis	22 days	Tue 1/18/05	Wed 2/16/05
27	Intervening Parties file Testimony	0 days	Tue 3/1/05	Tue 3/1/05
29	Intervening Party Discovery & Analysis by NSP	21 days	Tue 3/1/05	Wed 3/30/05
34	Settlement and Stipulation Conference	4 days	Tue 3/8/05	Fri 3/11/05
37	All Parties file Rebuttal	18 days	Mon 3/14/05	Mon 4/4/05
40	Prepare for hearings and cross-examination, including supporting "mock-cross" with Staff	5 days	Tue 3/29/05	Mon 4/4/05
41	Hearings	3 days	Wed 4/6/05	Fri 4/8/05
43	Motions to Correct Transcripts	0 days	Tue 4/19/05	Tue 4/19/05
44	Final list of Cross-examination exhibits	0 days	Tue 4/19/05	Tue 4/19/05
45	Initial Post-hearing briefs	0 days	Tue 4/26/05	Tue 4/26/05
46	Staff Memo	4 days	Wed 4/20/05	Mon 4/25/05
48	Staff Memo to Commission	0 days	Mon 5/23/05	Mon 5/23/05
49	Reply Briefs all parties	0 days	Tue 5/10/05	Tue 5/10/05
50	Commission Deliberations	3 days	Wed 5/25/05	Fri 5/27/05
52	Project Closeout	6 days	Mon 6/30/05	Mon 6/6/05



VI. Cost Proposal

Blue Ridge is pleased to submit this cost proposal to the Commission for its review and consideration As discussed throughout this proposal, we have assembled an outstanding group of experienced utility consultants and analysts to assist the Commission Staff in its investigation of Northern State Power Company's gas rate increase request in Case No PU-04-578 As the Commission is aware, the rate case process is dynamic and highly variable As issues develop new insights and research is needed to adequately prepare a position that is in the best interest of the ratepayers

Blue Ridge is prepared to offer the Commission a ***fixed price not to exceed*** cost for professional fees and expenses

Fixed Price/Not to Exceed Proposal
(including travel and out of pocket): **$83,205.00**

This cost represents the professional fees and expenses that Blue Ridge will provide for the duration of the rate case and related procedural schedule for Case No PU-04-578, which includes the Commission hearings, briefing and deliberation processes It is anticipated that some of the work related to this project will require an on-site presence of the project team at the Commission's offices in Bismarck, North Dakota When overnight travel is required, Blue Ridge will invoice the Commission for reasonable lodging, travel and meal expenses.

The table below summarizes the estimated costs for this proposal

Table 1 - Proposed Professional Hours, Costs and Expenses

ND PSC RFP, Case No PU-04-578
Northern States Power Company Rate Case Support
Blue Ridge Consulting Services,Inc Proposed Professional Hours, Costs and Expenses

		Donna Mullinax Project Manager	Michael J McGarry Subject Matter Expert	Howard Solganick Subject Matter Expert	Debra Rollins Consultant	Jeff Rosenblum Subject Matter Expert	Mike Dryjanski Subject Matter Expert	Total
Professional Services								
Project Start up		4	2	4	4	4	4	22
Project Management		12	2	2	12	2	2	32
Discovery		24	2	24	40	4	7	101
Analysis		32	4	40	60	32	12	180
Hearing Preparation/Settlement Prep		14	2	14	14	14	7	65
Attendance at Hearings/Settlement Conference		14	0	14	7	7	0	42
Testimony		12	2	12	0	12	0	38
Deliberations and other Final Meetings		12	4	12	12	7	7	54
Sub-Total Hours		**124**	**18**	**122**	**149**	**82**	**39**	**534**
Hourly Rate	0	$ 150 00	$ 137 50	$ 137 50	$ 70 00	$ 175 00	$ 125 00	$ 126 41
Consulting Fees		**$ 18,600**	**$ 2,475**	**$ 16,775**	**$ 10,430**	**$ 14,350**	**$ 4,875**	**$ 67,505**
		Number of Expected Trips to ND						
Expenses	Rate	3	1	2	1	2	1	
Hotel	$ 90	810	270	540	270	540	270	$ 2,700
Air Transportation	$ 850	2,550	850	1,700	850	1,700	850	$ 8,500
Meals per day	$ 40	480	160	320	160	320	160	$ 1,600
Ground Transportation	$ 50	600	-	-	-	-	-	$ 600
Miscellaneous	$ 20	240	80	160	80	160	80	$ 800
Total Expenses		**$ 4,680**	**$ 1,360**	**$ 2,720**	**$ 1,360**	**$ 2,720**	**$ 1,360**	**$ 14,200**
Administration, Supplies and Materials								
Admin Support (billed at $30 per hour)	$ 30						50	$ 1,500
Total Administration, Supplies and Materials								**$ 1,500**
Total Proposed Firm Fixed Price/Not to Exceed Costs								**$ 83,205**

VII. Conflict of Interest Disclaimer

In accordance with the North Dakota Public Service Commission Procurement Procedures, 8th Revision dated December 2002, Blue Ridge acknowledges the following Conflict of Interest Disclaimer with the submission of this proposal

The undersigned does hereby certify there is no financial substantive interest in the utilities which are or may be parties in this proceeding It is also certified that no business officer, partner, employee, agent, or any immediate family member has a substantive financial interest in the utilities, which are, or may be parties in this proceeding It is further certified that, should such a financial interest occur during the period of active involvement in the proceedings, the Commission will be immediately notified and shall have the right to terminate the contract

Blue Ridge Consulting Services, Inc	12/3/04
Applicant Organization	Date
Donna H. Mueller	Vice President / CFO
Signature of Certifying Official	Title

VIII. Appendices

Appendix 1 – Quality Assurance Plan
Appendix 2 – Project Team Resumes
Appendix 3 – Task Matrix
Appendix 4 – Examples of Schedules
Appendix 5 – Detailed Project Schedule

Appendix 1

Blue Ridge Consulting Services, Inc.

Quality Assurance Plan

Providing quality products and services for our clients is the main focus of Blue Ridge Consulting Services, Inc Quality is defined as adherence to specifications Efficiently creating a work product, timely in its delivery, with accurate and relevant results to meet the client's objectives is paramount

Blue Ridge is committed to ensure that the Commission receives the highest quality product and service. To that end, we make this commitment

> *If the Commission is unsatisfied with any work product such that the work does not meet the Commission's performance expectations as outlined in the solicitation and defined in an approved Task Assignment Plan, we will either re-do the work for no additional fee or not charge the Commission for the work*[1]

Our pledge is simple We will do the right work right, the first time.

In order to make the Commission this pledge, we have developed a peer review based Quality Assurance process that maximizes the cost-effectiveness of the work that we perform for the Commission This process is based on the many years of experience of the team in preparing analyses, studies, reports, testimony, issue papers, presentations and guiding and executing negotiations Every member of the team is experienced in providing quality work at various levels throughout their respective careers

The major elements of this peer review process include the following

- All presentations, written material and reports (excluding day-to-day correspondence such as emails, notes, etc) for the Commission will be submitted to the team for editorial and content review
- After being reviewed by the team, presentations, written material (i e testimony) and reports will be submitted to a professional editor for review, if appropriate
- All studies and analyses will be jointly reviewed by the Project Manager and the team member conducting the study/analysis Items to be confirmed include computations, assumptions and sources
- All sources will be properly documented using footnotes and comments within the appropriate sections of the analyses or study
- After completing the review with the Project Manager, all studies/analyses will be submitted to a team member experienced in the subject matter but not directly involved with completing the study/analyses This team member will critique the study/analyses for consistency, completeness and accuracy Particular attention will be paid to computational accuracy and flow of analyses
- This peer review process will be documented with a quality review form that will be included with the document, study or analysis presented to the Commission

[1] Any concerns arising out of performance evaluation and quality performance will be first addressed with the Contract Officer and then as outlined in the solicitation

- Quality review forms for testimony will clearly indicate the testimony revision level reviewed, the subject matter, the date of the review(s) and the team member responsible for the review
- All quality reviews will be signed by the applicable team member(s) performing the review

We believe that the above discussion clearly highlights both the breath and depth of our understanding of the issues that may impact the Commission as its utility support services provider We also believe that we have demonstrated the importance of the tasks that we are likely to perform under this solicitation. We are committed to providing the highest level of professional services for this engagement and look forward to a long and productive relationship with the Commission

Appendix 2 – Project Team Resumes

Donna H. Mullinax, CPA

Professional experience spans twenty-four years Expertise includes financial management, litigation/regulatory support, cost prudence reviews, due diligence reviews, economic viability studies, system implementation, auditing, quality assurance, technical cause analysis and production management

Financial Management

Responsible for all aspects of administration and finance as Chief Financial Officer and Vice President of Administration and Finance including bookkeeping, accounting, tax planning and preparation, calculation of depreciation, capitalized interest, fixed asset records and other related financial processes. Records were subject to an IRS compliance audit with no findings.

Litigation/Regulatory Support

Responsible for the development of various cost analyses in an attorney / client work product environment in connection with several civil litigations Project manager supporting expert witness in analyzing and calculating damages related to extended outages, analysis of budget vs actual financial performance, detail cost accounting analysis including re-estimation of actual and reasonable cost for expenses not specifically reported. Worked with expert witness to draft pre-filed testimony of factual findings and calculated damages. Developed questions and answers to support counsel during depositions and trial Testified before the COPUC on her findings related to a review of the electric commodity trading practices of a large utility

Cost Prudence Reviews

Team member for a major prudence cost review of a nuclear facility on behalf of the company. Activities focused on cost analysis support as well as case management and coordination activities.

Due Diligence Reviews

Project manager for numerous due diligence reviews coordinating cross-functional teams Senior financial analyst reviewing financial information and budget projections, risk identification and industry benchmarking in connection with potential corporation mergers and acquisitions and asset acquisitions.

Economic Viability Studies

Project manager for several economic viability studies using integrated spreadsheet analysis to identify and model various risk profiles and outcome sensitivities to determine the financial future of various electric generating facilities

System Implementation

Worked with small business and local governmental entities to design and implement accounting and business systems that addressed real world problems and concerns.

Developed accounting policy and procedure manuals for county governments, local utility, library, and water utility including fix asset accounting practices.

Auditing

Performed financial and compliance audits for county governments, utilities, and non-public businesses, including fixed asset reviews

Quality Assurance and Technical Cause Analysis

Provided customer interface for manufacturing to ensure products met rigid quality standards. Deviations resulted in implementation of appropriate corrective actions Performed analysis of complex quality and production problems to determine corrective actions through advanced statistical and problem solving Provided training for production and management on statistical quality control techniques

Production Management

Responsible for scheduling, cost, inventory control, labor allocations, and production quality

Education

Clemson University, B S in Administrative Management with honors – 1978
Clemson University, M S in Management – 1979
College for Financial Planning - 1994
NARUC Utility Rate School - 32nd Annual Eastern

Professional Certification

Certified Public Accountant, State of South Carolina – 1993
Certified Financial Planner – 1994

Professional Affiliations

Member of the American Institute of Certified Public Accountants (AICPA)
Member of the South Carolina Association of Certified Public Accountants (SCACPA)
Member of the Institute of Internal Auditors (IIA)

Michael J. McGarry, Sr.

Professional experience spans twenty-three years within the private and public sectors Expertise includes. regulatory and rate case management, project management and supervision, testimony and witness preparation, electric industry restructuring and deregulation as well as extensive experience in utility management and operations.

Regulatory and Rate Case Management

Worked with clients to manage all aspects of the regulatory and rate case process Developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners Provided project management and analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner

Assisted clients to prepare revenue requirement and cost of service analyses. Developed complex revenue requirement models to support rate request.

Developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports and annual wholesale rates for member cooperatives

Project Management and Supervision

Experienced multi-discipline team leader and project manager with skills that include having.

- Managed multi-discipline teams for a wide range of client engagements
- Developed and implemented project work plans
- Analyzed and planned interdivisional resource utilization
- Supervised, developed and coached interdivisional team members
- Created various reports and executive briefings

Testimony and Witness Preparation

Provided expert testimony in a number of proceedings before the New York State Public Service Commission These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, project management and others

Prepared testimony and witness preparation support on the behalf of clients for submission to Illinois Public Utilities Commission

Developed testimony for immediate supervisors in the areas of rates and tariffs

Restructuring, Unbundling, and Cost Allocation

Developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for a major mid-western utility. This included a detailed study where the company's plant-in-service and depreciation reserve was allocated to each unbundled function

Assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services

Utility Management and Operational Audits

Conducted over twenty comprehensive management and operational audits of investor-owned energy and telecommunications utilities A list of representative topics follows.

- Capital and operating budget process and practices
- Operations and maintenance expenses
- Crew operations
- Rate case pro forma adjustments

Supply Chain Management

Extensive experience and expertise in all aspects of supply chain management including e-Commerce, strategic sourcing, benchmarking and total cost of ownership analysis.

Education

Potsdam College, B A , Economics — 1981
University at Buffalo School of Management, MBA —1996

Associations

National Association of Purchasing Management
Squires Creek Homeowners Association – President
Boy Scouts of America – Committee Member, Troop 320, Mauldin, SC
St Mary Magdalene Catholic Church – Pastoral Council Member & Religious Education Teacher

Jeffrey I. Rosenblum, Ph.D.

Professional experience spans twenty years within the private and public sectors Expertise includes. macro-econometric modeling, design of electric utility rate structures, cost analysis and allocation, econometric forecasting, transfer pricing for multinational banking and brokerage firms as well as a broad range of issues relating to law and economics.

Regulatory and Rate Case Management

As a member of the Staff for the Public Utilities Commission of Texas, was responsible for litigation support, the design of electric utility rate structures, cost analysis and allocation, econometric forecasting, and participation in various rule-makings

Project Management and Supervision

Directed several cross-functional team in the design of economic studies for transfer pricing documentation and tax planning purposes

Coordinated global transfer pricing studies for documentation and planning purposes for multinational banking and brokerage firms and transfer pricing for state and local taxation purposes.

Testimony and Witness Preparation

Served as an expert witness Dockets in which he has testified include the request of Houston Lighting and Power to swap its ownership share in the South Texas Nuclear Project with the City of Austin, the prudence of TU Electric's buyback of capacity in the Comanche Peak Nuclear Generating Station, the prudence of El Paso Electric Company's decision to participate in the Palo Verde Nuclear Generating Station, and numerous other dockets involving rate design, forecasting, and other regulatory issues

Testified under live cross examination on over thirty separate occasions

Education

Ph D , Economics, University of Texas, 1992
B.S , Economics, State University of New York, 1983

Transfer Pricing Publications

- "An Alternative Approach to Accounting for Stock-Based Compensation in Cost Sharing," Tax Management Transfer Pricing Report, November 27, 2002
- "Estimating an Arm's-Length Interest Rate on Intercompany Loans," Tax Management Transfer Pricing Report, October 16, 2002 -
- "Determining an Arm's-Length Royalty Rate When a Company Creates a Service Subsidiary," Tax Management *Transfer Pricing Report*, July 11, 2001
- "Interquartile Ranges Microsoft Excel Versus the Section 482 Regulations," Tax Management *Transfer Pricing Report*, July 30, 1997
- "Analyzing Transfers of Financial Services Using Section 482 Methods," Tax Management *Transfer Pricing Report*, October 16, 1996 (with Steven D Felgran)

Howard Solganick, P. E.

Professional experience spans thirty years within the utility industry He has acted as an expert witness and arbitrator in a number of utility and regulatory areas and has extensive experience in regulatory relations He has led and/or participated in consulting projects to develop, design, optimize and implement both traditional utility operations and e-commerce businesses Mr Solganick has structured operating elements and business ventures, negotiated high value medium and long-term contracts, and implemented business systems, operating functions and profit centers

Key Areas of Expertise

- Operating responsibility and expert testimony in utility planning and operations including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, capacity and system planning, and regulatory issues
- Purchase and sale of long and short term bulk energy and capacity for utilities, independent power producers and end users under both regulated and competitive marketplaces
- Arbitration and mediation for high dollar value energy dispute resolution
- Regulatory relations and management for high profile situations – transmission line siting and approvals, powerplant siting and certificate of need processes and potential mass outages
- Customer relationship and negotiation services for utilities and vendors to the industry
- Management consulting for utilities, energy trading and production companies, contact (call) center providers, financial institutions, manufacturers, software providers and retailers
- Pre-audit counseling, management audit planning and implementation and post audit tracking and regulatory relations

Rates & Regulatory

As regulatory manager for a New Jersey utility was responsible for regulatory liaison and rate design for all customer classes including cost of service and tariff design. Provided expert testimony on rate design, load research, economic impacts, and all PURPA issues

As a utility's operational planner coordinated and had significant impact on load forecasting, demand side management, customer generation and its application to utility operations, utility owned and independent generation, transmission and distribution planning, and customer service performance levels Consulted and provided expert testimony on these interrelated areas.

As a potential expert witness for a major energy company analyzed historical procurement practices of a key competitor and provided critical insight for the client's evolving regulatory strategy before the FERC

As president of an independent power producers' trade association, led a regulatory intervention in Maryland to open the wholesale marketplace to competition Acted as the expert witness in the case, which resulted in a competitive procurement order by the commission

As a utility's project manager led the filing of New Jersey's first Notice of Intent for a Certificate of Need for a combined cycle powerplant. Working with the regulatory commission, the utility developed its filing as the commission was simultaneously developing its procedures and processes

As an operating manager for a New Jersey utility obtained regulatory approvals for a 230 kV transmission line and three major substations during a period of high public concern over EMF

For a major municipal gas utility assisted senior and operating management to prepare for a mandated management audit

As a utility's special projects manager created the utility's process for responding to the state's first legislatively mandated management audit. Developed a series of processes to coordinate, track, document, and respond to sensitive issues on an expedited basis.

As a planning manager for a utility directed corporate financial planning encompassing both major and minor forecasts and studies including presentations for the Board of Directors and the financial community

Energy Supply

For a residential/commercial real estate holding company performed a process review and developed and executed a procurement process for electric supply in a deregulated environment.

For a commercial real estate management company performed an evaluation of a distributed generation proposal including a site survey, cost benefit analysis and detailed operational and contract review.

For an independent power producer developed new projects and acquisitions, negotiated power purchase agreements, energy services agreements, fuel supply issues, site leases and analyzed project financial positions Successfully negotiated one of the first competitively bid power sales agreements with a public power entity and obtained the first IRS private letter ruling for a tax-exempt independent power financing.

As operating manager for a New Jersey utility negotiated over 800 MW of power purchase agreements with an aggregate value of over $9 billion, including developing significant dispatchability provisions Obtained required regulatory approvals in record time

For a major power trading company advised the operational team on the interrelationship of existing assets and PJM (Pennsylvania-New Jersey-Maryland, also includes Delaware, DC and now expanding to other states) power pooling operations

As an operating manager for a utility managed PJM Interconnection power purchase (interchange) pricing, performance testing of power plants and contract management of the company's unregulated cogeneration contract with the DuPont Company.

Working in conjunction with a major energy producer and refiner acted as project manager for a cogeneration facility study for a major refinery, which led to the construction of a 60 MW facility.

For a public power utility consortium examined forward looking marketing and financial plans, confirmed direction with the Board of Directors, assisted senior management to revise its strategic and operational plans and presented a recommendation for the future actions of the enterprise for consideration by the Board of Directors Specific results included the revitalization of the existing management team, the Board of Directors' adoption of that team's strategic plan with a commitment to move forward and the immediate authorization of bonuses for the management team for its efforts

For a money center bank acted as the subject matter expert in the conceptual development and business analysis of an electronic energy trading floor, which included the forward market, pre-existing relationships and preferred vendors, and provided full settlement capabilities

Arbitration

As the sole arbitrator presided over an issue of energy price escalation with a value of over $1,000,000 annually The arbitration included case management, discovery, depositions, extensive document exchange, six witnesses and a full briefing process. As defined in the parties' initial power purchase agreement, the arbitrator had to render a fully detailed decision in order for the parties to continue their business relationship for the eight years remaining under the agreement.

As chairman of a panel of three arbitrators was instrumental in the parties resolving a landlord tenant dispute over electrical submetering The amount in question exceeded $750,000.

Operations and Customer Service

As a lead consultant for an East Coast electric utility supported a two year effort to maintain and grow large key commercial and industrial accounts Allied responsibilities included the development of business models, negotiating positions, operations and support services for field forces, and regulatory support This project resulted in the long-term retention of a significant majority of the client's top 20 customers for periods of from five to twelve years.

For a million+ customer North American public power company managed (and acted as a subject matter expert) a call center performance review leading to a major consolidation of 28 sites into four physical call centers A follow-on engagement developed the implementation plan covering emergency response issues, human resources, customer care, new infrastructure, and network integration

For a large electric utility supported an extensive review of future opportunities for customer account services Important areas included definition of present and future activities, construction of possible scenarios, applicability of present internal costs, external competition, needs of future customers and business development and investment opportunities

On special assignment structured and performed distribution operations analyses including an evaluation of emergency operating and response capabilities.

As an emergency assignment acted as special liason between system operations and customer communications to avert significant customer disruptions due to a potential system failure

On special assignment led a team generating key performance indicators for over 60 utility operating areas and integrated the KPI into a new compensation and performance enhancement package.

Business Planning and Implementation

For an unregulated utility affiliate acted as an advisor to review the conceptual business plan, financial model, and operating assumptions for a planned entry into the New Jersey retail energy market. Major issues included ISO operations, tariff interpretations, customer service performance and expected market penetration

For a high volume energy retailer investigated various business models to enhance profitability A number of scenarios, including both traditional improvement opportunities and various e-business arrangements, were generated and evaluated Extensive investigation and evaluation were structured with potential vendors/suppliers to reduce costs and raise profitability A customer profitability concept was created to evaluate the retailer's portfolio

For two utility clients acted as project manager and subject matter expert on a joint client-consultant team comprised of 40 people. The engagement included customer management systems, contact (call) centers, new products and services, technology planning, and financial modeling of the venture This project resulted in the creation of a new business entity for the energy industry

For an energy conservation company assisted the internal staff in defining their business model, implementing their Internet based marketing and service delivery platform, defining the relationship with key allies, negotiating performance contracts and performing design reviews as needed Key issues included a timely implementation plan

With a major petroleum marketer explored the potential establishment of a joint marketing arrangement for energy and telecommunications This analysis included consumer testing of a combined bill and double branding

For a major electric utility acted as an advisor to the general manager implementing a customer choice initiative available to all customers Major issues included the concept

of an anti-slamming policy, peer group review, the use of external third parties to enhance credibility, and regulatory considerations

Education

Master of Science--Engineering Management (minor Law)

Drexel University (evening program)

Bachelor of Science--Mechanical Engineering (minor Economics)

Carnegie Mellon University

Planning, Zoning and Land Use Courses—Rutgers University

Arbitration and Mediation Training Courses—American Arbitration Association

Professional Credentials and Activities

Professional Engineer in Pennsylvania and New Jersey
Vice-Chairperson Middletown Township (PA) Planning Commission
Past member of New Jersey Board of Regulatory Commissioners Advisory Council on Electricity Planning and Procurement
Commercial Arbitrator - American Arbitration Association
Past President of the Mid Atlantic Independent Power Producers, a trade organization
Past member of the Electric Power Research Institute's Planning Methods Committee
Professional Planner (Land Use) in New Jersey (inactive)
Chairman (past), Egg Harbor Township (NJ) and member (past), Raritan Township (NJ) Zoning Board of Adjustment
Author, Energy Pulse Article – Why Won't You Listen to the Actresses?

Michael T. Dryjanski, CPA

Professional experience spans twenty-five combined years of service in the accounting and financial area including twenty years in the utility industry Experience includes regulated utility rate case development with a primary emphasis on rate base, capital expenditures, case management activities, and facility cost allocation studies

Consulting

Litigation Support

Responsible for the development of various cost analyses in an attorney / client work product environment

Cost Allocation

Responsible for the development of facility cost identification and allocation of cost to wholesale distribution facilities for delivery points of wholesale customers pursuant to Docket ER99-4415

Responsible for the coordination activities of an electric depreciation study for a major Midwest utility. Activities and responsibilities include the development of cost and transaction analysis, preparation of supporting documentation in to be utilized by the Company witness. Concurrent activities included on-site education of company staff with respect to the development of a depreciation accrual rate

Utility Background

Cost Prudence Reviews

Team member for a major prudence cost review of a nuclear facility on behalf of the company Activities focused on cost analysis support as well as case management and coordination activities

Litigation Support

Provided litigation support in conjunction with a major property damage suit Support was critical in a successful conclusion and financial recovery by the company

Regulatory proceedings and rate cases

Provided continual support in various electric and gas regulatory proceedings before the Illinois Commerce Commission (ICC). Support activities included development of documentation and analysis of major capital projects, testimony preparation and witness support, electric and gas depreciation studies and related accrual rates, rate base development, issue analysis and response, and docket management support

Developed a functional asset separation cost study that was submitted in testimony in ICC Docket 98-0860 as well as provided the related written and verbal testimony before the Illinois Commerce Commission (ICC) The study became the basis of an administrative and general expense (A&G) cost allocation study that was submitted in

the same docket Data developed from this project was also integrated into the Company's Open Access Transmission Tariff (OATT) filing before the FERC.

In ICC Docket 01-0432, co-developed post-test year plant additions in the Company's most recent Delivery Service Tariff case which resulted in definitional change of "known and measurable" and allowed for planned expenditure reflection in the determination of total rate base

In the Washington Gas Light Company (WGL) rate case, FC1016, for the Washington D C Public Service Commission advised on the reasonableness of various pro forma adjustments proposed by WGL and co-developed an in-depth assessment of the WGL's proposed changes in depreciation rates and methodologies

Currently involved in a gas rate case, ICC Docket 04-0476 This support of the filing utility in the presentation of the company's rate base and revenue requirement include activities such as the development of a capital additions forecast, analysis and development of an asset allocation study, and development and/or review of various related pro forma adjustments

Deregulation / Industry Restructuring

Provided strategic support to management for the Company's electric deregulation initiative with timely and thorough assessments of restructuring activities in other states in order to determine applicability and impact on the Company's restructuring activities within Illinois and to facilitate the development of management's strategy Activity culminated in the passage of electric deregulation legislation in December 1997

System Implementation

Responsible for the planning, coordination, installation and implementation of a $1million plus capital asset accounting system

General Utility Accounting

As Team Leader, responsible for a six person staff associated with the capital asset accounting process Supervisory responsibilities include adherence to GAAP and regulatory requirements from the FERC and ICC, calculation of depreciation, capitalized interest, fixed asset records and other related financial processes

Other activities included development of policies, practices, procedures, O&M vs capital training programs, efficiency improvements, rate case support, tax department support during IRS audits and the implementation of related aspects of a new financial management and budgeting system.

Education

Chicago State University, B S., 1977, Major Accounting
University of Illinois at Springfield, M B A , 1996 Concentration Finance
Depreciation Programs, Inc Grand Rapids, MI
Professional Training Systems - Electric Utility System Operations - 1991
NARUC Regulatory Training - 1993

Professional Certification and Affiliations

Certified Public Accountant, State of Illinois, 1979

Member of Society of Depreciation Professionals

Debra A. Rollins

Ms Debra Rollins is a Consultant and Business Manager with Blue Ridge Consulting Services, Inc. Ms. Rollins has over twelve years of professional experience in the areas of internet management, project management, financial projects, logistics, training and human resources

Financial Management

Assists the Chief Financial Officer in administration and financial responsibilities Developed and implemented intranet site for integrated logistics company to monitor financial activity. Reviewed and analyzed regional P&L's ($43M) for cost savings opportunities

Litigation Support

Team member that supported expert witness in analyzing and calculating damages related to extended outage Supported team with document management, draft testimony, and exhibits

Regulator Affairs / Rate Case Management

Team member that assisted the District of Columbia Public Service Commission in the evaluation for the accounting and depreciation aspect and revenue requirements of a rate case filed by a gas company.

Supply Chain Management / Logistics

Developed operational design, warehouse layout, material flow, process flow/improvement, and supplier trouble shooting for premier automotive manufacturer. Flowcharted all procedures involved in implementation, trained associates on new system Conducted time studies, cost analysis, route optimization, site selection, facility design, layout design, statistical analysis, load planning, and scheduling. Provided logistics analysis for a Business to Business / Business to Consumer (B2B/B2C) e-commerce company Assisted in developing logistical strategy for new business model. Conducted freight analysis that resulted in revamping freight damage procedures, recouping lost revenue.

System Implementation

Implemented automated Warehouse Management System that included sequencing of parts. Conducted training for various logistics, warehouse management and financial programs

Education

Limestone College, BS in Business Management, Magna Cum Laude – 1998

Professional Certification

NARUC Utility Rate School - 32nd Annual Eastern

Appendix 3
Task Matrix

Skills/Experience/Task	Mullinax	McGarry	Solganick	Dryanski	Rosenblum	Rollins
Specific Areas						
Evaluate NSP's cost of service requirements	Y	Y	Y	Y	Y	
Review all pro forma adjustments	Y	Y	Y	Y	Y	
Detailed analysis of NSP's deferred debits and credits and regulatory assets and liabilities	Y	Y		Y	Y	
Examine historical capital planning & spending	Y	Y	Y	Y	Y	Y
Track and trend revenue erosion since the last rate increase	Y		Y			Y
Review NSP's wage and compensation program	Y		Y			
Analyze the Company's management structure		Y	Y		Y	
Evaluate the effectiveness of NSP's business processes and benchmark against other companies of general accepted business practices	Y	Y	Y			Y
Review NSP's separation of costs between regulated and unregulated operations (if applicable)		Y	Y	Y		
Examine the Company's jurisdictional separation		Y	Y	Y		
Skills						
Revenue Requirements & Rate Base	Y	Y	Y	Y	Y	
Operating Expenses and Pro Forma Adjustments	Y	Y	Y	Y		
Rate of Return	Y	Y	Y	Y	Y	
Revenue, Load and Demand Adjustments (weather and economic)			Y			Y
Depreciation Expenses			Y	Y		
Amortization of Special or Recurring Items	Y		Y	Y		
Taxes	Y	Y		Y		
Gains and Losses from Disposition of Utility Assets	Y		Y	Y	Y	
AFUDC	Y	Y		Y		
Interest Charges	Y	Y		Y		
Cost of Capital	Y	Y	Y		Y	
Planning, Forecasting & Budgeting		Y	Y			
Distribution		Y	Y			
Customer Service			Y			
Regulatory		Y	Y		Y	
Finance			Y		Y	
Information Services		Y	Y			
Operational Reviews and Audits		Y	Y			
Planning and Budgeting	Y	Y	Y	Y		
Human Resources, Organization and Management	Y		Y			
Business Process Analysis and Review	Y	Y	Y			Y
Affiliate Transactions		Y	Y	Y		
Testimony and Cross Examination						
Testimony Development	Y	Y	Y	Y	Y	Y
Testimony as Witness	Y	Y	Y	Y	Y	
Project Management	Y	Y	Y	Y	Y	Y

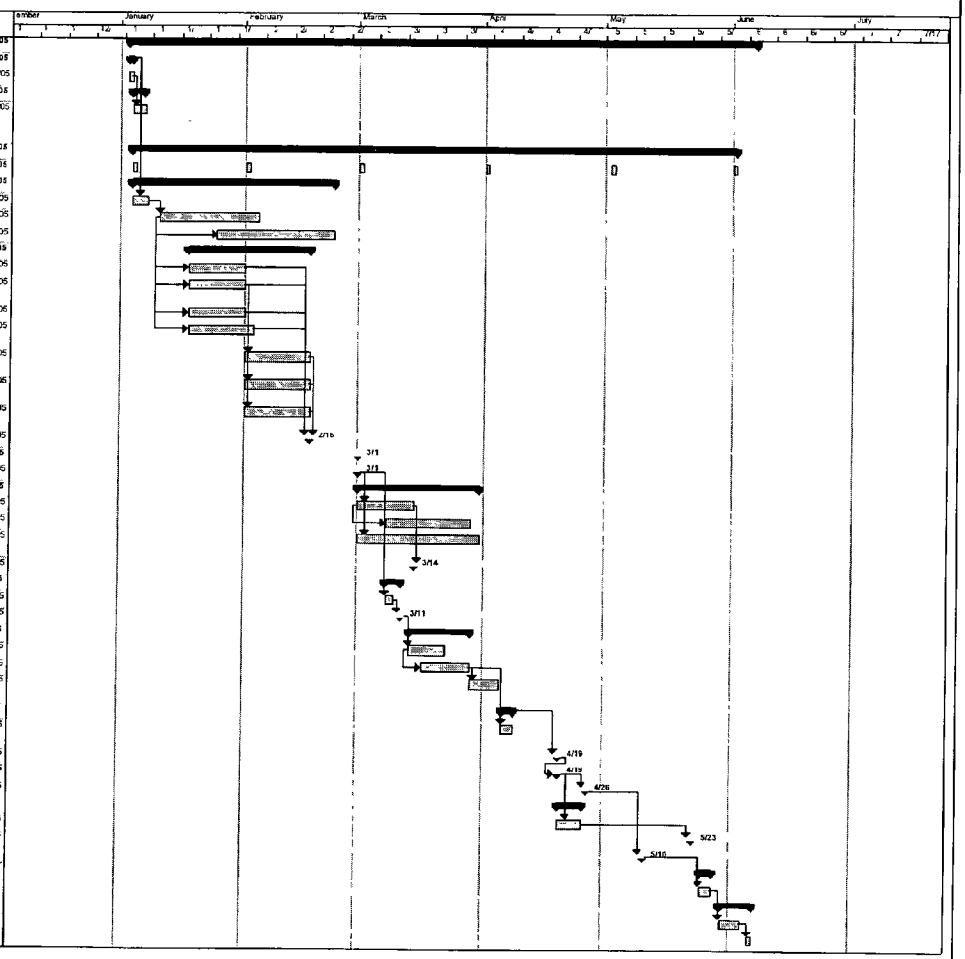
Appendix 4
Example of Revenue Requirement Schedules

Description	Adjustment Reference	DC Per Books	DC Ratemaking Adjustment	DC Ratemaking Amount	DC Pro Forma Adjustment	DC Pro Forma Amount	Required Increase
A	B	C	D	E = C + D	F	G = E + F	H
Operating Revenues	Revenue Study	$ 192,698,390	$ 2,762,468	$ 195,460,858	$ (1,057,513)	$ 194,403,345	$ 14,521,034
Operating Expenses							
Operation	Adjustment Summary 31	$ 117,896,105	$ 1,670,083	$ 119,566,188	$ (6,539,620)	$ 113,026,568	$ 341,875
Maintenance	Adjustment Summary 38	8,932,894	-	8,932,894	269,094	9,201,988	
Depreciation	Adjustment Summary 40	15,627,116	-	15,627,116	1,135,469	16,762,585	
Amortization		1,234,642	-	1,234,642	-	1,234,642	
Interest on Customer Deposits	Adjustment Summary 42	109,009	-	109,009	(57,258)	51,751	
Interest on Supplier Refunds		3,509	-	3,509	-	3,509	
General Taxes	Adjustment Summary 49	26,091,157	2,082,854	28,174,011	1,065,285	29,239,296	1,417,916
Other Income Taxes	Adjustment Summary 52	2,363,271	(632,806)	1,730,465	378,679	2,109,144	1,273,288
Expenses Before Federal Income Taxes	=2>9	$ 172,257,703	$ 3,120,131	$ 175,377,834	$ (3,748,351)	$ 171,629,483	$ 3,033,079
Federal Income Taxes	Adjustment Summary 53	$ 6,646,932	$ (3,718,110)	$ 2,928,822	$ 1,196,159	$ 4,124,981	$ 4,021,209
Investment Tax Credit Adjustments		(282,254)	-	(282,254)		(282,254)	
Deferred Income Taxes	Adjustment Summary 55	(4,897,604)	9,002,435	4,104,831	-	4,104,831	
Total Operating Expenses	=10>13	$ 173,724,777	$ 8,404,456	$ 182,129,233	$ (2,552,192)	$ 179,577,041	$ 7,054,288
Net Operating Income	=1-14	$ 18,973,613	$ (5,641,988)	$ 13,331,625	$ 1,494,679	$ 14,826,304	$ 7,466,746
Net Income Adjustments							
AFUDC	Financial Statement	(10,282)	-	(10,282)	10,282	-	
LCP Equity Accrual	Financial Statement	-	-	-	-	-	-
Net Operating Income - Adjusted	=15>17	$ 18,963,331	$ (5,641,988)	$ 13,321,343	$ 1,504,961	$ 14,826,304	$ 7,466,746
Net Rate Base	Rate Base Summary 26	$ 267,177,410	$ (16,530,680)	$ 250,646,730	$ (9,640,793)	$ 241,005,937	
Return Earned	=18/19	7.10%		5.31%		6.15%	
Less							
Interest Expense		$ 8,398,992		$ 7,544,467		$ 7,254,279	
Preferred Dividends		244,706		200,517		192,805	
Net Income Available for Common Equity		$ 10,319,633		$ 5,576,359		$ 7,379,220	
% Applicable for Common		50.30%		50.30%		50.30%	
Common Equity Capital		$ 134,390,237		$ 126,075,305		$ 121,225,986	
Return Earned on Common Equity		7.68%		4.42%		6.09%	

Appendix 5
Detailed Project Schedule

North Dakota Public Service Commission
Request for Proposal Case No. PU-04 578
Northern States Power Company Rate Increase Request
Illustrative Schedule

ID	Task Name	Start	Finish
1	**NSP Rate Case (PU-04-578)**	Mon 1/3/05	Mon 6/6/05
2	Contract Award	Mon 1/3/05	Mon 1/3/05
3	Project Start Up	Mon 1/3/05	Mon 1/3/05
4	**Finalize workplan with Staff**	Tue 1/4/05	Thu 1/6/05
5	schedule	Tue 1/4/05	Thu 1/6/05
6	**Project Management**	Tue 1/4/05	Wed 6/1/05
7	**Monthly Report**	Tue 1/4/05	Wed 6/1/05
14	**Discovery**	Tue 1/4/05	Tue 2/22/05
15	Review NSP and Intervening Party filings	Tue 1/4/05	Fri 1/7/05
16	Document Requests to NSP	Tue 1/11/05	Thu 2/3/05
17	NSP Responds to DR's	Tue 1/25/05	Tue 2/22/05
18	**NSP Primary Case Analysis**	Tue 1/18/05	Wed 2/16/05
19	Compare income statements from previous cases	Tue 1/18/05	Mon 1/31/05
20	from previous to current case	Tue 1/18/05	Mon 1/31/05
21	Review and evaluate the Cost of Capital issues	Tue 1/18/05	Mon 1/31/05
22	and past rate schedules	Tue 1/18/05	Wed 2/2/05
23	responses to interrogatory requests	Tue 2/1/05	Wed 2/16/05
24	including all class allocators and rate of return by class	Tue 2/1/05	Wed 2/16/05
25	service and rate design	Tue 2/1/05	Wed 2/16/05
26	Position Summary for Staff Review	Wed 2/16/05	Wed 2/16/05
27	**Intervening Parties file Testimony**	Tue 3/1/05	Tue 3/1/05
28	Intervening Party testimony	Tue 3/1/05	Tue 3/1/05
29	**Intervening Party Discovery & Analysis by NSP**	Tue 3/1/05	Wed 3/30/05
30	NSP submits DR's to Intervening Parties	Tue 3/1/05	Mon 3/14/05
31	Intervening parties respond to DR's	Tue 3/8/05	Mon 3/28/05
32	positions on issues	Tue 3/1/05	Wed 3/30/05
33	Prepare Intervening party summary for Staff Review	Mon 3/14/05	Mon 3/14/05
34	**Settlement and Stipulation Conference**	Tue 3/8/05	Fri 3/11/05
35	Assist Staff with Settlement and Stipulation Conference	Tue 3/8/05	Wed 3/9/05
36	Staff Report on Settlement/Stipulation Conference	Fri 3/11/05	Fri 3/11/05
37	**All Parties file Rebuttal**	Mon 3/14/05	Mon 3/28/05
38	DR's to parties on rebuttal	Mon 3/14/05	Tue 3/22/05
39	Responses to DR's on rebuttal	Thu 3/17/05	Mon 3/28/05
40	mock-cross with Staff	Tue 3/29/05	Mon 4/4/05
41	**Hearings**	Wed 4/6/05	Fri 4/8/05
42	cross examination of utility and intervening parties	Wed 4/6/05	Fri 4/8/05
43	Motions to Correct Transcripts	Tue 4/19/05	Tue 4/19/05
44	Final list of Cross-examination exhibits	Tue 4/19/05	Tue 4/19/05
45	Initial Post-hearing briefs	Tue 4/26/05	Tue 4/26/05
46	**Staff Memo**	Wed 4/20/05	Mon 4/25/05
47	Prepare Staff summary memo	Wed 4/20/05	Mon 4/25/05
48	Staff Memo to Commission	Mon 5/23/05	Mon 5/23/05
49	Reply Briefs - all parties	Tue 5/10/05	Tue 5/10/05
50	**Commission Deliberations**	Wed 5/25/05	Fri 5/27/05
51	Conduct issue presentation to Commission	Wed 5/25/05	Fri 5/27/05
52	**Project Closeout**	Mon 5/30/05	Mon 6/6/05
53	Return all confidential materials and workproducts	Mon 5/30/05	Fri 6/3/05
54	Conduct Client Post project review and evaluation	Mon 6/6/05	Mon 6/6/05



Confidential

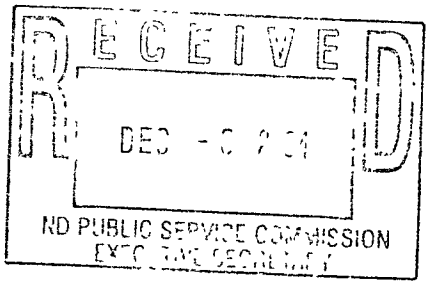
Thu 12/2/04

BRB
BUSINESS RESEARCH BUREAU

School of Business
University of South Dakota
414 E Clark Street
Vermillion, SD 57069-2390

Telephone (605) 677-5287

FAX (605) 677-5427



December 3, 2004

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Dear Ms. Jeffcoat-Sacco

Enclosed please find the original and five copies of our Request for Proposal, Case No. PU-04-578.

Sincerely,

Wade Druin
Director, Business Research Bureau

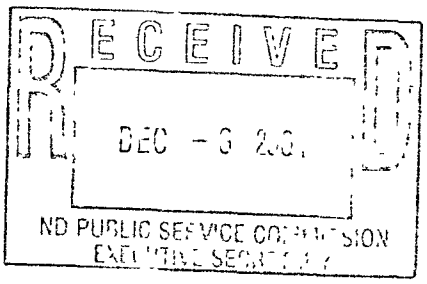
22 PU-04-578 Pages 44
Proposal
by Business Research Bureau
12/06/2004 CC Comm Legal PUD (4) Mike

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Proposal

North Dakota Public Service Commission

CASE NO. PU-04-578
December 3, 2004

Business Research Bureau
University of South Dakota
Patterson Hall 132
414 E. Clark St.
Vermillion, SD 57069

Proposal

Introduction

The Business Research Bureau at The University of South Dakota submits this proposal to the North Dakota Public Service Commission to assist the Commission staff in its investigation of Northern States Power Company's (NSP's) proposed natural gas rate increases, referenced by the commission as Case No. PU-04-578.

With access to the institutional capabilities of the AACSB-International accredited School of Business at the University, the Business Research Bureau (BRB) is fully capable of conducting the investigation and analysis needed to explore the justification and reasonableness of the proposed rate increases. Principle investigators for this project include:

- Ralph J. Brown, Ph.D., Professor of Economics
- Randall E. Waldron, Ph.D., Associate Professor of Economics
- Wade D. Druin, J.D., Director of the Business Research Bureau

This team has expertise in economics and law, with specializations in labor economics and in econometric and regulatory analysis, as well as experience in the analysis of public utility industries and in public testimony. Short biographies follow the proposal details, and a curriculum vita is attached for each investigator.

Proposal and Work Approach

The Request for Proposal identifies seven specific duties for the consultant, in order to investigate, analyze, and provide testimony concerning the proposed rate increase. These duties include:

- professional analysis and review of the filing
- prepare and conduct discovery as necessary
- monthly progress reports of discovery, conclusions and recommendations
- prepare and file written testimony
- provide oral testimony
- assist staff in preparing cross-examination of the witnesses of other parties to the proceeding
- assist staff in the preparation of proposed findings of fact

The work in each of these areas will address NSP's proposed rate base, cost of capital, regulated net income and rate design.

This proposal encompasses work on all seven areas, using a consistent approach for each that focuses on the statistical analysis of historical trends and current market conditions, using forecasts derived from data obtained through discovery and from independent sources.

Among the issues to be addressed is the question of the distribution of costs among different service constituencies. An overall increase of 1.8% in revenue has been requested, but the proposed increase derived from residential users, and particularly low use customers, is substantially more. Justification for these increases should be analyzed in an appropriate economic framework that focuses on the marginal cost of delivering services to specific customer classes.

This economic framework begins with the concept that pricing should correspond to marginal costs where possible to attain the greatest possible allocative efficiency. Optimal deviations from this scheme will be considered in the course of analyzing the effects of allocating fixed costs and overhead. In particular, low use customers appear to face a greater share of the reallocation of such costs, as noted in the Request for Proposal. The BRB will scrutinize NSP's class cost of service study carefully for methodological appropriateness and reasonableness of conclusions.

The BRB analysis will also consider the fundamental cost structure of the firm, utilizing accounting data, but not constrained by accounting cost allocation concepts. The BRB will use econometric techniques to calculate the appropriate costs measurements on the basis of data provided by the firm and the commission, and that acquired through the discovery process. The BRB analysis will disaggregate to the extent possible sources of various costs, distinguished both by customer class and type of service. The BRB research team includes the expertise in econometric and regulatory analysis to do this consultation effectively

The BRB team will engage in the consulting duties as indicated in the Request for Proposal. A proposed timetable with division of responsibilities among the team is as follows:

Starting Jan 1, 2005	Jan-05				Feb-05				Mar-05				Apr-05				May-05			
Week #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
(1) Professional analysis and review																				
(2) Prepare and conduct discovery																				
(3) Monthly progress reports																				
(4) Prepare/file written testimony																				
(5) Provide oral testimony																				
(6) Assist in preparing cross-exam																				
(7) Assist in prep of proposed find																				

Participant Roles	1	2	3
(1) Professional Preliminary analysis and review	x	x	x
(2) Discovery	x	x	
(3) Monthly progress reports		x	
(4) Prepare and file written testimony	x	x	x
(5) Provide oral testimony	x	x	
(6) Assist staff in preparing cross-exam	x		x
(7) Assist staff in preparation of proposed findings	x	x	x

Chart Key	
Dr. Brown	1
Dr Waldron	2
Druin	3

The Investigators - Capacity

The Business Research Bureau (BRB) and its personnel will serve as the managers of this Project. The Business Research Bureau has engaged in business research and consulting services for over 50 years, and has extensive experience in both the private and public arenas. The BRB provides support to faculty, students and businesses by conducting research for public and private organizations, serving as depository for business and economic data, and distributing economic research and analysis to the business and public community. The Bureau is a charter member of the Association for University Business and Economic Research (AUBER).

The BRB has provided businesses and governmental entities with research services in the areas of economics, statistical process control, public finance, investment strategies, banking, marketing, health care administration, issue research, and public opinion surveying. The BRB also oversees the State Data Center (SDC), Kids Count, the Small Business Development Center (SBDC), Management Education Services (MES), Crash Outcome Data Evaluation System (CODES), the South Dakota Family Business Initiative (SDFBI), the Freeman Initiative in Rural Entrepreneurship (FIRE), the Institute for the Study of Rural Banking and Financial Markets, and the South Dakota Bankers Association Chair of Banking.

For the purpose of this application, the primary participants will include:

Ralph J. Brown (Ph.D. in economics, University of Colorado) is a labor economist who has extensive academic and practical experience. Dr. Brown teaches Labor Economics, which deals in part with employee compensation plans. In addition, he has authored a number of articles dealing with labor economics. In particular, he was the research economist for Governor Janklow's Wage Study Task Force in 1999-2000. He authored a report (see curriculum vita) summarized in "The South Dakota Wage Study: Determinants of State Differences in Average Annual Pay."

Dr. Brown has also worked as an expert witness for thirty-three years (33) in cases involving the projection of lost wages and salaries, fringe benefits, and pension plans. He has provided testimony in hundreds of cases and is experienced in adversarial settings. He has testified hundreds of times in courtrooms throughout the Midwest. (See list of testimonials since 1993 attached to C.V.) Dr. Brown is also a member of the Governor's Council of Economic Advisors. He presents a quarterly forecast of the South Dakota Economy to state policymakers and assists in the preparation of annual revenues for the Governor's Budget. Dr. Brown has been a member of the Council since it was created in the early 1990's. Dr. Brown also has extensive experience consulting with other agencies of the state and federal governments. He is very familiar with data sources of wage and salary data. He has consulted with the South Dakota Department of Labor and has assisted them on forecasting key labor market variables

Randall E. Waldron (Ph.D. in economics, Vanderbilt University) is an economist specializing in industrial organization and managerial economics. He has taught at The University of South Dakota for ten years, and has co-authored a study on the restructuring of South Dakota's electricity markets, "Electricity Pricing in a Restructured Electric Power Industry." This study was conducted by the Business Research Bureau for South Dakota's Rural Electric Cooperative, and was recognized as a leading study by national authorities on the provision of rural electricity. Dr. Waldron has also consulted on antitrust projects, both privately and on behalf of the State of South Dakota, including one in which he estimated damages leading to a settlement in a mil price-fixing suit.

Wade D. Druin (JD, University of South Dakota) is a South Dakota licensed attorney. Prior to coming to the University, he has practiced law for several years. On numerous occasions, he conducted direct and cross-examination of witnesses and assisted with the preparation of testimony. He has taught at the University of South Dakota for over 5 years. He currently is the managing director of the Business Research Bureau at the School of Business and the University.

Nancy Craig, Information Officer at the Business Research Bureau, provides support to the SD State Data Center (SD SDC). The SD SDC was established as part of the Business Research Bureau in 1981 by Executive Order of the Governor to serve as the State's official source for population and socio-economic statistics. Nancy is responsible for identifying resources to be able to provide information to the public and private sector data users. As part of the joint agreement with the U.S. Census Bureau to disseminate

census data, Nancy also assists the Census Bureau with various projects such as updating group quarter data and boundary updates. Nancy coordinates the publication of releases from the SD SDC which includes compiling data and publication layout. Releases are made available in either paper reports or CD-ROM.

Combined Price/Bid

The Business Research Bureau will complete the entire project to include all of the issues for Twenty-Five Thousand Dollars ($25,000.00). It is not practical for the BRB to bifurcate the issues and give pricing by issue.

The bid includes all travel cost. It was assumed that there would be one trip to Bismarck, ND.

Compliance

The University of South Dakota complies with all applicable Equal Employment Opportunity laws and regulations and with applicable provisions of the Americans with Disabilities Act of 1991.

References for Ralph Brown and the Business Research Bureau

Kenneth E. Barker
Attorney at Law
P.O. Box 100
Belle Fourche, SD 57117
Phone: (605) 723-8000

Russell Janklow
431 N. Phillips Avenue, Suite 400
Sioux Falls, SD 57104
Phone: (605) 338-4304

Greg Eiseland
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Rapid City, SD 57009
Phone: (605) 348-7300

Jason Dilges, Commissioner
Bureau of Finance and Management
South Dakota Capitol Building
Phone: (605) 773-4149

Daniel Greenwood
30 First Avenue East
Dickinson, ND 58602
Phone: (701) 225-6074

Paul Lundberg
505 5th Street Frances Bldg
Sioux City, IA 51102
Phone: (712) 255-4444

Paul Ebeltoft Jr.
P.O. Box 1097
Dickinson, ND 58603
Phone (701) 227-1841

Matthew F. Gaffey
Assistant Attorney General
Department of Roads - Legal Counsel
PO Box 94759
Lincoln, NE 68509
Phone (402) 479-4611

Conflict of Interest

Disclaimer

The undersigned does hereby certify there is no financial substantive interest in the utilities which are or may be parties in this proceeding. It is also certified that no business officer, partner, employee, agent, or any immediate family member has a substantive financial interest in the utilities which are or may be parties in this proceeding. It is further certified that, should a financial interest occur during the period of active involvement in the proceedings, the Commission will be immediately notified and shall have the right to terminate the contract.

Signature

12/3/04
Date

Director, Business Research Bureau
Title

University of South Dakota
Company Name

THE UNIVERSITY OF SOUTH DAKOTA

FACULTY CURRICULUM VITAE

Name of Faculty: **RALPH J. BROWN**

DEGREES:

University of Colorado, Boulder, CO, *Ph.D., Economics, 1970.

South Dakota State University, Brookings, SD, M.S Economics, 1968

Northern State College, Aberdeen SD, B S., Economics, 1967

TEACHING EXPERIENCE:

University of South Dakota, 1977-Present, Professor of Economics.

Northern State College, 1970-1977, Assistant, Associate and Professor of Economics.

University of Colorado, 1968-1970, Teaching Assistant and Teaching Associate

OTHER PROFESSIONAL EXPERIENCE:

Partner in Economic Analysts and Associates, 1978-Present.

Workshop on Economic Education for Secondary teachers, Summer 1978, 1977, 1976.

Research Assistant, South Dakota State University, 1967-1968.

HONORS:

2002 School of Business Nominee for Belbas Larson Award for Excellence in Teaching

2003 School of Business Nominee for Belbas Larson Award for Excellence in Teaching

2003 Honorable mention for Belbas Larson Award for Excellence in Teaching at University of South Dakota

2003 University of South Dakota, School of Business, Great Teaching Prize of 2003 - Econometrics

PUBLICATIONS/RESEARCH/CREATIVE WORKS:

Publications and Papers:

With Scott Selk, "Economic Trends on American Indian Reservations in South Dakota," *South Dakota Business Review,* Vol. LXI, No. 4, June 2003.

"Is South Dakota a Poor State?" *South Dakota Business Review,* Vol. LXI, No 1, September, 2002

"State Differences in the Federal Balance of Payments," *South Dakota Business Review*, Vol LX, No. 2, December, 2001.

"The Cyclical Sensitivity of the South Dakota Economy: Revisited," *South Dakota Business Review*, Vol. LIX, No. 3, March, 2001.

"Do Right-to-Work Laws Reduce Union Membership?" Paper Presented at the Missouri Valley Economics Association, February 2001.

"The Myth of Energy Independence" Unpublished paper December, 2000.

"A Statistical Analysis of the Impact of the Forward Sioux Falls Program," Business Research Bureau, School of Business, University of South Dakota, Vermillion, SD 57609

"South Dakota Rankings on Wages, Personal Income, and Gross State Product," *South Dakota Business Review*, Vol. LIX, No. 1, September, 2000.

"The Political Economy of Ethanol" Paper Presented at the Missouri Valley Economics Association, February 2000.

"A Simple Method for the Measurement of the Economic Importance of Variables in Multiple Regression Analysis" Paper Presented at the Missouri Valley Economics Association, February 2000.

"The South Dakota Wage Study. Determinants of State Differences in Average Annual Pay", *South Dakota Business Review*, Vol. LIX, No 3, March, 2000.

Papers Prepared for the Governor's Wage Study Task Force, Fall 1999.

"The South Dakota Wage Study· State Differences in Average Annual Pay"

"Why Wages Differ?"

"Explaining the Wage Gap: Why are SD Wages so Low? "

"Explaining the Wage Gap. Why are SD Wages so Low? The Regional Facts"

"Differences in Average Wage Per Worker and Personal Income Per Capita Measures"

"Cities, Clusters, Firm Size, and Productivity"

"A Note on Industry and Occupation Mix"

"Measures of Geographical Differences in the Cost of Living"

"Saving Rates by Estimates for Single Persons by Income, Age, and Gender," *Journal of Legal Economics,* Vol. 8, Number 2, Fall 1998.

"Helping Experts in Personal Injury and Death Cases: What Legal Assistants Should Know," *FACTS & FINDINGS The Journal for Legal Assistants*, Volume XXV Issue 3, November, 1998.

(Reprinted in *The Verdict*, Newsletter of the Ventura County Legal Assistants, October, 1999

(Reprinted in *What Legal Assistants Should Know,* Snell and Wilmer Educational Paralegal Business Conference Handbook. September, 1999.

Book Review of *Expert Economic Testimony Reference Guides for Judges and Attorneys*, by Ireland, Horner, Rodgers, Gaughan, Trout, and Piette. *Journal of Economics*, Vol XXIV, No. 2, 1998.

With Matt C. Rousu, "Enrollment Trends and Out-of-State Tuition," *South Dakota Business Review*, Vol. LVII, No. 4, June, 1998.

"The Measure of Damages in Loss to the Estate Cases " Paper Presented at the Missouri Valley Economics Association, February 1998.

With Dennis A. Johnson and Randall E. Waldron, "The Economics of Recycling. A Case Study," A Study prepared for the City of Vermillion, South Dakota presented at Missouri Valley Economic Association meeting March 1, 1997.

"Whither Manufacturing?", *South Dakota Business Review*, Vol LV, No 2, December, 1996.

"Loss of Earning Capacity in the Case of a Farmer," *Litigation Economics*, Vol. 1, No 1, Summer 1995

"Trials of an Expert Witness· Cross-Examination," Proceedings of the Management Functions and Applications, Vol 13, Number 3, 1995

With Dennis A Johnson, *The Economic Impact of Limiting Drug Price Discounts in South Dakota,* a study prepared for the Pharmaceutical Manufacturers Research Association of America, September 10, 1994

"Do Locational Amenities Equalize Utility Across States?," *Journal of Economics*, Volume XX, No 1, 1994

"Support for Public Higher Education: State-By-State Comparisons," Prepared for the South Dakota Board of Regent, August 1991.

"An Economic Impact Study of a Proposed Wet Corn Milling Plant in Southeastern South Dakota," Prepared for the Governor's Office of Economic Development, January 1991.

"Personal Consumption: The Case of Retirement Period Consumption," *Journal of Forensic Economics*, Spring/Summer, 1991 (Vol. 4, Number 2)

With Dennis A. Johnson, "Determinants of Faculty Salaries in Public Institutions of Higher Education in South Dakota, 1989," Prepared for the South Dakota Board of Regents, May 1990.

With Linda Lea Viken, "Recognition of Homemaker Career Opportunity Cost in Marital Dissolution Cases," *South Dakota Law Review,* Vol. 35, Issue 1, 1990.

An Analysis of Economies of Scale in South Dakota School Districts, Prepared for the Commission on Government Cost Efficiency and Tax Reform, July 1989

"New Gross State Product Estimates," *South Dakota Business Review*, Vol XLVIII, No. 3, March 1989

With Raymond J Ring, "A Study of the Impact of Dakota Proposition II on Property Tax Revenues in South Dakota", *South Dakota Business Review*, Vol. XLVII, No 2, September, 1988.

With Raymond J. Ring, *A Study of the Impact of Dakota Proposition II on Property Tax Revenues in South Dakota*, Bulletin No. 134, Business Research Bureau, School of Business, University of South Dakota, July 1988.

"Financing Public Higher Education in South Dakota," *South Dakota, Business Review*, Vol. XLVI, No 4, May, 1988.

"The South Dakota Economy· An Historical Perspective," *South Dakota Business Review*, Vol XLVII, No. 1, July, 1988.

A Study of the Support for Public Higher Education in South Dakota A Comparative And Historical Analysis, Publication 88-5, Office of the Executive Director, South Dakota Board of Regents, Pierre, South Dakota, January 1988.

With Dennis A Johnson, *An Analysis of the Impact of the Nonresident Tuition Rate on Non-resident Enrollment Demand*, Bulletin No 132, Business Research Bureau, School of Business, University of South Dakota, July 1987.

With P. Dougherty and T Dougherty, *Public Debt in South Dakota Economic Survey and Outlook*, 4th Edition, Prepared for Dougherty Dawkins, Strand and Yost, Investment Bankers, Minneapolis, MN, November 1986.

"The Implicit Inflation and Interest Rates in Discounting Personal Injury Economic Losses," *Journal of Risk and Insurance*, September 1986.

With P. Dougherty, *Public Debt In South Dakota Economic Survey and Outlook,* 3rd Edition, Prepared for Dougherty, Dawkins, Strand, and Yost Inc., Investment Bankers, Minneapolis, MN, November 1984.

With Jerry Johnson, "Perspective 1983-Outlook 1984, "*South Dakota Business Review*, Vol. XLII, No 3, March 1984.

With Dennis Johnson, "Wrongful Death and Personal Injury: Economics and the Law," *South Dakota Law Review*, Vol. XLI,Winter, 1983.

"Is the Inflation Cycle Dead?,"*South Dakota Business Review*, Vol. XLI, No. 3, February, 1983.

With Jerry Johnson,"Perspective 1982, Outlook 1983,"*South Dakota Business Review*, Vol. XLI, No 3, February 1983.

With Dennis A. Johnson and Richard Shane, "An Approach to the Grazing Fee Problem on Indian Lands," *Journal of the American Society of Farm Manager and Rural Appraisers*, Vol. 46, No. 1, April 1982.

With David I. Knudson, *Public Debt in South Dakota Survey and Outlook*, 2nd Edition, Prepared for Dougherty, Dawkins, Strand and Eckstrom Investment Bankers, Minneapolis, Minnesota, August 1982.

With Richard Shane, *Simulating the Statewide Impact of Irrigation Development on South Dakota*, Bulletin No 129, Business Research Bureau, School of Business, University of South Dakota, December 1981.

"Simulating the Impact of an Irrigation Project on a Small Regional Economy," *Growth and Change*, Vol. 12, No 2, April 1981

"Inflation and the New Monetary Aggregates," *Business Economics*, Vol. XVI, No. 3, May 1981.

With Dennis A Johnson, "Valuation, Inflation, and the Discount Rate," *Appraisal Journal*, Vol. XLVIII, October 1980

"The Cyclical Sensitivity of the South Dakota Economy," *South Dakota Business Review*, Vol. XXXIX, No. 1, August 1980

With David I. Knudson, *Public Debt in South Dakota Survey and Outlook*, Prepared for Dougherty, Dawkins, Strand and Eckstrom Investment Bankers, Minneapolis, Minnesota, August 1980.

With Jerry W. Johnson, "Productivity, Inflation, and Living Standards," *South Dakota Business Review*, Vol. XXXVIII, No 4, May 1980

"High Prices or Rationing," *Colorado Business Review*, Vol.41, No. 3, March 1980.

With Richard Shane, "An Analysis of the Impact of Irrigation Development on the Economy of South Central South Dakota," Water Resources Institute, South Dakota State University, October 1980

"Simulating the Impact of Irrigation Development, "*South Dakota Business Review*, Vol XXXVII, No. 5, August 1979.

"A Study of Certain Aspects of the South Dakota Housing Development Authority Program," a memorandum published by the State Legislative Research Council, State Capital, Pierre,South Dakota, August 1979.

With Richard Shane, *Simulating the Impact of Irrigation Development in the Third Planning District*, Bulletin No 127, Business Research Bureau, School of Business, University of South Dakota, 1979.

"Do High Gasoline Prices Matter?," *South Dakota Business Review*, Vol. XXXVII, No. 4, May 1979.

With Jerry W Johnson, "Perspective 1978, Outlook 1979,"*South Dakota Business Review*, Vol. XXXVIII, No. 3, February 1979.

With Dennis Johnson and Greg Gullickson, "Reducing Property Taxes in South Dakota," *South Dakota Business Review*, Vol XXXVIII,No. 3, November 1978. Reprinted in South Dakota *Municipalities*, Vol. 45, No 9, March 1979

With Jerry W Johnson, "Perspectives 1977, Outlook 1978,"*South Dakota Business Review*, Vol XXXVI, No.3, February 1978

"A Regional Econometric Model with an Endogenous Agricultural Sector," *Proceedings of the Pittsburgh Conference on Computer Modeling and Simulation*, April 1978.

With Jerry Schmitz, "Appraising Easements The Case of the Wetland Easement," *Appraisal Journal*, Vol. XLV, No 2, April 1978

"The Impact of the Wetlands Easement Program on Agricultural Land Values," *Land Economics*, Vol. 52, No 4, November 1976.

Abstracted in *Journal of Economic Literature*, Vol XV, No 2, June 1977.

With Michael Morrissey, "The Demand for Public Higher Education in South Dakota: With Projections to 1985," *South Dakota Social Science Association Journal*, Summer 1975.

"On the Selection of the Best Predictive Model in Multiple Regression Analysis," I,*The Appraisal Journal,* Vol.XLII, No. 4, October 1974

"1974-Another Year of Inflation," *Economic Forecaster*, April 1974. Published by First National Bank of Aberdeen.

"Why Are Interest Rates So High?," *Economic Forecaster*, March 1974. Published by First National Bank of Aberdeen.

"South Dakota and the National Economic Slowdown," *Economic Forecaster*, January 1974 Published by First National Bank of Aberdeen.

Research and Consultation:

Economic Advisor to the Governor's Council for Tax Decision, 1971-1972.

Economic Advisor to the Governor's Task Force on Economic Development, 1972.

Board of Trustee of South Dakota Economic Education Association, 1973.

Member of Academic Resources Council-Advisory Board to State of South Dakota.

Consultant to Attorneys on the estimation of economic loss due to wrongful death and personal injury or loss of business profits

Consultant to Department of Interior, Bureau of Indian Affairs, Land Appraisal Division, 1973-76. Development of Computer-based Appraisal Models

Consultant to Department of Interior, Fish and Wildlife Service, Wetlands program 1974-76 Evaluation of Impact of Easement of Land Values and Development of and Equitable Pay Schedule

Consultant to Department of Interior, National Park Service, Cypress Project, 1975-76. Development of Computer-based Appraisal Models for Land Acquisition project

Constructed an Econometric Model of South Dakota under contract with the South Dakota State Planning Bureau, Summer 1976

Prepared study which was presented in testimony before the Federal Power Commission in Washington, D C., January 1977. Case involved economic impact of natural gas curtailments in Montana-Dakota Utility Service area

Constructed Agricultural Econometric Model of South Dakota under contract with the South Dakota State Planning Bureau, Summer 1977

Presented Summer Workshop in Economic Education for Secondary Teachers, Summer 1975, 1976, 1977, 1978.

Constructed Econometric Model for Third Planning and Development District for the purpose of estimating the impact of a large-scale irrigation project for Department of Natural Resources and Development and Legislative Research Council of State of South Dakota, Spring 1979.

Consultant to the Office of the Secretary of the U S Department of Interior on the design of multiple regression models for rental house appraisal Wrote technical standards manual. 1980

Consultant to Legislative Research Council on legislative matters, 1978-79.

Analyzed the impact of the South Dakota Housing Development Authority for Legislative Research Council, Summer 1979.

Testified before Committee on Bonding Review concerning irrigation impacts on South Dakota, October 1978.

Testified before Committee on Bonding Review concerning irrigation model, August 1979.

Testified before Committee on Bonding Review concerning South Dakota Housing Development Authority, August 1979

Testified before Committee on Bonding Review concerning South Dakota Housing Development Authority, August 1979.

Testified before Executive Board of Legislative Research Council on Irrigation study, July 1979

Testified before Water Resources Board on irrigation model, October 1979

Testified before Committee on Bonding Review concerning Housing Development Authority, October 1979

Developed Grazing Fee Formula for Cheyenne River Indian Reservation for United Sioux tribes. Consultant to United Sioux Tribes on development of computer-based appraisal models, Summer 1980

Consultant to United Sioux Tribes on development of grazing fee formula for Cheyenne River Reservation, Summer 1980.

Expert Witness for U.S. Department of Justice in Yosemite National Park case involving computer-based setting of rental rates, 1983.

Consultant to Office of the Secretary of the U.S. Department of Interior. Testified in court in Fresno, California concerning the appraisal of rents in Yosemite National Park, 1983-1984

Constructed South Dakota Labor Market econometric model for South Dakota Department of Labor and prepare four forecasts per year, 1981-88.

Constructed Econometric Model to simulate statewide impact of irrigation projects for Department of Water and Natural Resources, 1980-81.

Consultant to the Council of Presidents of South Dakota Higher Education System on impact of changes in non-resident tuition, 1986. (See publications).

Consultant to the South Dakota Board of Regents on the financial

support for higher education. (See publications).

Consultant to Sweetman Construction Company, Sioux Falls, South Dakota on economic impact of quarry in Minnehaha County, July-August 1987 Testified before Minnehaha County Planning and Zoning Board and Minnehaha County Commission.

Consultant to South Dakota Attorney General as damage expert in ETSI litigation 1984-1988. Jury awarded $660 million

Member South Dakota Investment Council, 1987-1992. Vice-Chairman, 1988, Chairman, 1989-90

Testified before Joint Appropriations Committee concerning financing of public higher education in South Dakota, January 1988

Presented testimony on impact of changes in nonresident tuition rate on nonresident enrollment before Board of Regents meeting in Brookings, May 1988

Consultant to Bureau of Budget and Finance on outlook for SD Economy, 1988

Presented SD economy outlook seminar for Standard and Poor's meeting for Governor Mickelsen's meeting, June 1988

Presented SD economy outlook seminar for Moody's Financial Services meeting for Governor Mickelsen's meeting, June
1988.

Prepared with Ray Ring study of impact of Dakota Proposition II on property tax revenues in South Dakota (See publications)

Economic Advisor to Governor's Advisory Commission on Taxation, 1988

Economic Advisor to South Dakota Tax Study Commission, 1989-90

Referee for papers submitted to Global Finance Journal, California State University, Fresno, California.

Consultant to the South Dakota Board of Regents on regression analysis to test for evidence of gender or ethnic origin discrimination in faculty salaries at six public institutions of higher education in South Dakota, 1990.

Consultant to Bureau of Budget and Finance on development of econometric forecasting system for state of South Dakota, 1990-

Testified before Joint Rules Committee on discount rate for lump-sum settlement for workman's compensation claims, August 1990

Consultant to Governor's Office on Economic Development on Economic Impact of Proposed Wet Corn Milling Plant, January 1991.

Economic Advisor to Governor's Council of Economic Advisors, 1991-.

Presenter on topic of economic development and state fiscal policy to Governor's Tax Strategy Briefing, September 1992

Presented talk on Economic Development Trends in the Tri-State area to the Annual Tri-State Governor's Conference held at Dakota Dunes, South Dakota, October 1992

Presented talk on use of economist in forensic work to the South Dakota Legal Assistants Association in Sioux Falls,October 1992

Presented paper on "Do Locational Amenities Equalize Utility Across States?" Annual Meeting of the Missouri Valley Economics Association, Memphis, Tennessee, February 1993 Revised version of paper to published in *Journal of Economics*

Presented paper on "Economic Loss in the Case of a Farmer" Annual Meeting of the Missouri Valley Economics Association, St Louis, Missouri, February 1994.

Discussant of papers on forensic economics, Annual Meeting of the Missouri Valley Economics Association, Kansas City, Missouri, February 1995.

Referee for manuscript review for *Journal of Forensic Economics*

Consultant to Pharmaceutical Manufacturers Research Association of America on unitary pricing law in South Dakota, Summer 1994

Presented paper on "Trials of an Expert Witness: Cross-Examination," The Association of Management (AoM) 13th Annual International Conference, Vancouver, British Columbia, August 1995.

Session Chair, Consulting and Professional Issues, The Association of Management (AoM) 13th Annual International Conference, Vancouver, British Columbia, August 1995.

Presented results of Economics of Recycling Study to Missouri Valley Joint Powers Committee, March 1997. With Dennis A Johnson and Randall Waldron.

Presented paper on "The Economics of Recycling: A Case Study," with Randall E. Waldron at Great Plains Waste Management Conference, March 1997.

Speech for Civic Issues in the 21st Century Conference, University of South Dakota, March 25-26, 1997. Speech on the topic of "Too Much Political Participation."

Speaker Yankton Rotary Club, March 1997.

Presented results of Economics of Recycling Study to Missouri Valley Joint Powers Committee, August 1997. With Dennis A. Johnson and Randall Waldron

Research on Nonresident Enrollment and Tuition Patterns Research for President James Abbott, University of South Dakota. With Dennis A. Johnson and Leon Korte

Speaker on the Future of the Welfare State, Political Economy Club Forum, March 1998

Speaker on the Impact of Canada-South Dakota Trade War, International Economics Forum, September 1998

Research Economist Governor's Wage Study Task Force, Summer and Fall 1999

Speaker in Political Economy Club Forum on Ethanol Should It Be Subsidized? November 1999.

Faculty Exchange with Council on International Educational Exchange, Argentina and Chile, June 2001.

Speaker Vermillion Rotary Club on the Argentine Economy, August 2001.

Speaker Vermillion Elephant Club on the Chile Economy, August 2001.

Speaker USD International Forum on Is Latin America Falling Apart?, March 2002

Speaker USD International Forum on Do We have an Energy Crisis?, April 2002.

Speaker, Business School Faculty Forum On Chile and Argentina, April 2002

Speaker with Lillian Lopez on Chile and Argentina, South Dakota Investment Society, April 2002

"A Primer on the South Dakota Economy: Are We a Poor State?" USD Faculty Forum, Sponsored by USD School of Business and the Office of Research and Graduate Education. 02/04/03.

Recipient Of Governor Rounds 2003 Faculty Award for Teaching with Technology grsnt

MEMBERSHIP IN PROFESSIONAL SOCIETIES:

American Economic Association

Midwest Economic Association

South Dakota Social Science Association (now defunct)

South Dakota Council on Economic Education, Board of Trustees

South Dakota Investment Society

Western Regional Science Association

National Association of Forensic Economists

Member of Midwestern Regional Board of Directors

Association of Management

UNIVERSITY/COMMUNITY/STATE ACTIVITIES:

University:

Member of Library Committee, 1981-82.

Member of University Research Committee, 1981-82

Member of Committee to Study the Status of Women, University of South Dakota, 1978.

Member of Social Science Curriculum Committee, Northern State College, 1973-1975

Member of Faculty Personnel Committee, Northern State College, 1976-77.

Member of Faculty Senate, Northern State College, 1976-77.

Lecturer law school class on Legal Remedies and class on

Trial Techniques each year on use of economist.

Expert Witness, Mock Court Trial for Law Day, University of South Dakota Law School, 1982.

Expert Witness, Mock Court Trial for Law Day, University of South Dakota Law School, 1986.

Expert Witness, Mock Court Trial for Law Day, University of South Dakota Law School, 1988.

Undergraduate economics advisor, 1986-.

Lecturer for Determining Disability and Worth Seminar, Kilian Community College, Sioux Falls, April 1989

Member of General Research Committee, Chairman, University of South Dakota, 1990-.

Participant on Use of Expert Witness and Demonstrative Evidence, South Dakota Trial Lawyers Association, "Nuts and Bolts" Seminar, November 1990.

Participant in Demonstration Trial Association of Trial Lawyers of America Meeting in Toronto, July 1991

Member of Steering Committee for Business School Accreditation, Chairman of Sub-Committee for Institutional Effectiveness, 1991-94.

Co-Chairman of Search Committee for Director of Business Research Committee, 1991-92

Expert Witness, Mock Trail for Law School, University of South Dakota Law School, 1993.

Member of University of South Dakota Efficiency Plan Committee, 1995-1996.

Chairman of Mission Statement Committee for School of Business, 2001-2002

Community/State Activities:

Who's Who in the Midwest, 1981-82.

Speeches to Rotary(2), Cosmopolitan(2), Exchange, and Sertoma Clubs in Aberdeen on economic topics.

Resource person on topic of Oahe Irrigation Project for South Dakota Association of the Humanities, Aberdeen (3 meetings)

Resource person for AAUW meeting on Economic Status of Women.

Resource person on topic of the Dakota Proposition for South Dakota Association of the Humanities, Scotland and Brookings.

Keynote speaker for Annual Business Conference, Northern State College, October 1979

Speaker for Water Goals Conference in Pierre, December 1979.

Speaker for South Dakota Consumer Finance Convention in Sioux Falls, June 1980

Speaker for Argus Leader Economic Outlook Conference, August 1980.

Speaker for Sioux Falls Chamber on South Dakota Economic Outlook, April 1982

Speaker for S D. Society of Certified Public Accountants in Yankton, July 1982

Lecturer for Continuing Legal Education group on use of economist in wrongful death and personal injury cases,1978.

Speaker for Watertown Chamber of Commerce, January 1983

Speaker for Northern State College Annual Business Conference, Surviving the 1980's

Speaker for the Sioux Falls Argus Leader Management Seminar, July 1983.

Panel discussion on structured settlements SD Bar Association (CLE) Rapid City, May 1983

Speaker for education workshop on economics at School of Education, University of South Dakota, April 1984.

Speaker School of Business Advisory Board Meeting, Rapid City, October, 1986.

Speaker for the Sioux Fall Argus Leader and Sioux Falls Chamber Economic Seminar, April 1987

Speaker for Student Higher Education Days at the Legislature, South Dakota Student Federation, January 1988.

Member South Dakota Investment Council, 1987-1992. Vice-Chairman of South Dakota

Investment Council, 1988-89. Chairman of South Dakota Investment Council, 1989-1991.

Speaker at South Dakota School Administrators Conference on impact of Dakota Proposition II, School of Education, University of South Dakota, September 1988.

Speaker and panel member for Broadcaster's Day presentation on South Dakota economy, South Dakota State University, October 1988.

Speaker at Elk Point School Board Meeting on the impact of Dakota Proposition II, October 1988.

Speaker on topic of Economic Testimony in Alimony Cases for State Bar of South Dakota Committee on Continuing Legal Education, Watertown, S D., October 1989

Speech on Economic Value of Homemaker, Center for Economic Education at Augustana College, Sioux Falls, December 1989.

Member of Board of Director of Vermillion Development Company, 1991-. Vice-President, 1991-92.

Who's Who in Business and Finance, 1991

Speaker at Southern Union County Economic Development Corporation meeting on economic trends, January, 1993.

Speaker Yankton Rotary Club, March 1997

Speaker on the Future of the Welfare State, Political Economy Club Forum, March 1998

Speaker on the Impact of Canada-South Dakota Trade War, International Economics Forum, September 1998.

Speaker in Political Economy Club Forum on Ethanol Should It Be Subsidized? November 1999

Speaker Vermillion Rotary Club on the Argentine Economy, August 2001

Speaker Vermillion Elephant Club on the Chile Economy, August 2001

Speaker USD International Forum on Is Latin America Falling Apart? April 2002

Member of Citizen taskforce on the Vermillion School District Opt-Out Issue

"A Primer on the South Dakota Economy: Are We a Poor State?" USD Faculty Forum, Sponsored by USD School of Business and the Office of Research and Graduate Education. 02/04/03.

*Dissertation Title: *A Factor Analysis of the Differential Growth Process of Rural-Urban Centers in the Upper Midwest*

Testimony in Court - Ralph J. Brown

Case	Number	Plain/Def	Attorney	Location
1 Peterson	2/93	P	Brad Schreiber	state/SD/Bison
2 Batcheller	7/93	P	Larry Piersol	state/SD/SF
3 Sybesma	10/93	P	Robert Schaub	state/SD/LakeAnde
4 Wahl	12/93	P	Dann Greenwood	state/ND/Williston
5 Hanson	1/94	P	Rick Johnson	state/SD/Madison
6 North	2/94	P	Gary Jensen	state/IA/Council Blu
7 Webber	4/94	P	Brad Schreiber	federal/SD/RC
8 Saingen	5/94	P	Martin Trotzig	state/IA/LeMars
9 Cole	5/94	P	S Meierhenry	state/SD/SF
10 Welch	6/94	P	Brad Kollars	federal/Iowa/Sioux
11 Red Elk	6/94	P	Terry Pechota	federal/SD/Rapid C
12 Delzer	6/94	P	Brad Schreiber	state/SD/Deadwooc
13 Mahoney et al	6/94	P	Ken Barker	federal/WY/Cheyen
14 Bjork	7/94	P	Jim Roby	state/SD/SF
15 Goldammer	7/94	P	John Blackburn	state/SD/SF
16 Wright	7/94	P	Alvin Pahlke	state/SD/Mitchell
17 Soma	7/94	P	Dennis Duncan	state/SD/Vermillion
18 Perman	8/94	P	Ron Wager	state/SD/Aberdeen
19 Daniels	8/94	P	Gerald Reade	state/SD/Vermillion
20 Erickson	8/94	P	David Palmer	state/SD/SF
21 Harlow	8/94	P	Jeff Sveen	state/SD/Aberdeen
22 Lujan	9/94	P	Don Shultz	federal/SD/RC
23 Rickert	12/94	P	Don Shultz	state/SD/Rapid City
24 Nolte	12/94	P	Murray Ogborn	state/NE/Omaha
25 Tapp	12/94	P	Palhke	state/NE/Chadron
26 Keiser	1/95	Divorce	McCulloch	state/SD/Elk Point
27 Read	2/95	P	Sanford	federal/SD/SF
28 Scherr	2/95	P	Cotton	federal/ND/Bismarc

29 Meyer	2/95	P	Steve Johnson	state/SD/Brookings
30 Schreiber	2/95	P	Debra Watson	state/SD/RC
31 Rasmussen	3/95	P	Gellhaus	state/SD/Aberdeen
32 Bottum	4/95	P	Lee Burd	federal/SD/SF
33 Kaltenbach	4/95	P	Bonynge	state/SD/Canton
34 Schnee	4/95	P	Padrnos	state/SD/Salem
35 Stevenson	5/95	P	Freeman	state/SD/Mitchell
36 Sullivan	5/95	P	Steve Johnson	federal/SD/SF
37 Schettler	5/95	Divorce	Kay Dull	State/IA/Caroll
38 Dullerud	6/95	P	Gale Johnson	state/SD/SF
39 Andreson	8/95	D	Nooney	state/SD/RC
40 Hagan	8/95	P	Oliver	state/SD/Aberdeen
41 Skvicalo	9/95	D	Christensen	state/SD/Deadwood
42 Sexton	9/95	P	Keane	state/IA/SC
43 Bovee	10/95	P	Jones	state/IA/Spirit Lake
44 Steinhauer	10/95	P	Nichols	state/SD/Flandreau
45 Munsen	10/95	P	Hoy	state/SD/SF
46 Allphin	10/95	P	Stratton	state/NE/Columbus
47 Thompson	10/95	P	Munger	state/IA/SC
48 Selby	11/95	P	Schreiber	state/SD/RC
49 Bland	11/95	P	Day	state/SD/Mitchell
50 Shultz	11/95	P	Ford	federal/SD/SF
51 Dearborn	11/95	P	Wengert	federal/IA/SC
52 Carr	11/95	P	Wengert	federal/IA/SC
53 Armijo	12/95	P	Doyle	state/SD/SF
54 Daniels	2/96	P	Bonynge	state/SD/RC
55 Koch	4/96	P	Stratton	state/NE/Ord
56 Allen	4/96	P	Fox	state/SD/Chamberl
57 Elrod	5/96	P	Christensen	state/SD/SF
58 Tunender	5/96	P	Issenhuth	state/SD/Madison
59 Dahl	5/96	P	Turbak	state/SD/Clear lake
60 Stuart	6/96	P	Bottaro	state/IA/SC

61 Olson	7/96	P	Janklow	arbitration MPLS
62 Davis	7/96	P	Dougherty	state/SD/SF
63 Hammrich	9/96	P	Schaffer	state/SD/RC
64 Hayes	9/96	P	Eiseland	state/SD/Sturgis
65 Jami	10/96	P	Hoy	state/SD/White Rive
66 Didier	10/96	P	Swedlund	state/SD/SF
67 Bryant	10/96	P	S Johnson	state/SD/Vermillion
68 Frankman	10/96	P	Schaffer	Federal/SD/SF
69 Swett	11/96	P	Nooney	Federal/SD/RC
70 Hermann	11/96	P	Killinger	Federal/SD/SC
71 Anderson	1/97	P	Burnett	state/NE/Wayne
72 Hanson	2/97	P	Giles	state/SD/SF
73 Honomichl	4/97	P	Wilka	state/SD/SF
74 Myers	5/97	P	Whiting	state/SD/Winner
75 Selchert	5/97	P	Larson	Federal/SD/SF
76 Eygabroad	5/97	P	Martens	state/IA/Pocahontas
77 Landmark	6/97	P	Schoenbeck	state/SD/Sisseton
78 Schweitzberger	6/97	P	McMahon	state/IA/Ida Grove
79 Harmon	6/97	P	Hecht	state/IA/SC
80 Gregorson	7/97	P	Connot	state/SD/LakeAnde
81 Harris	7/97	P	Hieb	Federal/SD/SF
82 Hayden	8/97	P	Schreiber	state/SD/RC
83 Kaiser	8/97	P	Schmitz	state/SD/Belle Four
84 Jones	8/97	P	Johnson	state/SD/Huron
85 Hofer	10/97	P	Shelton	state/SD/Huron
86 Daktronics	10/97	D	Lange	Federal/SD/SF
87 Fiedler	11/97	P	Collier	state/SD/Yankton
88 Peterson	12/97	P	Burke	state/SD/Salem
89 Sletten	12/97	P	Binger	state/SD/SF
90 Eckes	12/97	P	Ramsey	state/ND/Dickinson
91 Hey	12/97	P	Heidepriem	state/SD/SF
92 Huling	1/98	P	Eiseland	state/SD/RC

93 Williams	1/98	P	Burns	state/SD/Canton
94 Buum	3/98	P	Miller	state/SD/Elk Point
95 Freiberghouse	4/98	P	Fox	state/SD/Yankton
96 Reimer	4/98	P	Busick	state/NE/Omaha
97 McClintock	4/98	P	Cook	state/IA/Spirit Lake
98 Chase	6/98	P	Casey	state/SD/SF
99 McIlravy et al	6/98	P	Barker	Federal/WY/CH
100 Tri-County	7/98	P	Schaub	state/SD/Chamberl
101 Howe	8/98	P	Hoskins	state/SD/Mitchell
102 Mack	9/98	P	King	state/SD/Watertowr
103 Campbell	10/98	P	Scott	Federa/IA/SC
104 Alexander	11/98	P	Bowen	Federal/SD/Pierre
105 Peterson	11/98	P	Bridgeman	state/
106 Wolcott	12/98	P	Johnson	Federal/SD/SF
107 Hardin	1/99	P	Nadolski	state/Brookings
108 DeVries	2/99	P	Burnette	state/IA/SC
109 Still	2/99	P	Hecht	state/IA/SC
110 Lock	4/99	P	James	state/Yankton
111 Nash	6/99	P	Crew	Federal/SD/Pierre
112 Kritzmire	7/99	P	Johnson	state/SD/SF
113 Athey	7/99	P	Hertz	Federal/SD/SF
114 Wiese	8/99	P	Turbak	state/SD/Milbank
115 Wilson	9/99	P	Weidemeirer	state/SD/Yankton
116 Critser	10/99	P	Landon	state/SD/SF
117 Roos	11/99	P	Klinker	state/IA/Spencer
118 Schlidt	1/00	P	Urbigkit	Federal/WY/Caspe
119 Hayes	1/00	P	Eiseland	State/SD/Deadwoo
120 Kvols	1/00	P	Harmelink	State/NE/Wayne
121 Prine	1/00	P	Munger	Federal/IA/SC
122 Kidd	2/00	P	Burns	Federal/SD/SF
123 Tramp	3/00	P	Stevens	Federal/SD/SF
124 Pavel	3/00	P	Howey-Fox	State/SD/Yankton

125 Entringer	3/00	P	Hurley	State/SD/Deadwoo
126 Thompson	5/00	P	Claggett	State/SD/RC
127 Olson	8/00	P	Janklow	State/SD/Brookings
128 Jacobs	9/00	P	Connot	State/SD/RC
129 Brady	10/00	P	Thompson	State/SD/Canton
130 Mattis	11/00	P	Anderson	Federal/SD/SF
131 Baarts	11/00	P	Healey	State/SD/Brookings
132 Ferrell	11/00	P	Swanson	Federal/IA/Cedar F
133 Kaarup	12/00	P	Hertz	State/SD/SF
134 Swedlund	1/01	P	Bridgman	Federal/SD/SF
135 Griffiths	5/01	P	Turbak	State/SD/Aberdeen
136 Jung	7/01	P	Russman	State/SD/Aberdeen
137 Wylie	8/01	P	Hoffman	State/SD/SF
138 Big Stone Partners	12/01	P	Gerdes	State/SD/Aberdeen
139 Buschkamp	2/02	P	Blakeman	State/NE/Center
140 Olson	2/02	P	Fox	State/NE/Yankton
141 Ruden	4/02	P	Munger	State/IA/Orange Cit
142 Athey	5/02	P	Horner	State/SD/SF
143 Kappeman	5/02	P	Eiesland	Federal/SD/SF
144 Stoffers	5/02	P	Breit	State/SD/Brookings
145 Burhenn	1/03	P	Meierhenry	State/SD/SF
146 Esser	3/03	P	Crew	State/SD/SF
147 Maynard	8/03	P	Rasmussen	State/SD/Mobridge
148 Kriz	8/03	P	Parsons	DOL/Hearing/Sisse

Testimony by Deposition-Ralph J. Brown

1 Schroeder	1/95	P	Crary
2 Schumacher	1/95	P	Bindner
3 Schreiber	2/95	P	Watson
4 Schwietert	3/95	P	Shultz
5 Schaeffer	4/95	P	Barker

6 Boldt	4/95	P	Barker
7 Schettler	5/95	Divorce	Kay Dull
8 Whalen	5/95	P	Schreiber
9 Dolly	6/95	P	Shultz
10 Slagel	7/95	P	Nooney
11 Uhl	7/95	P	Ellwanger
12 Stone	7/95	P	Beardsley
13 Hofland	8/95	P	Morris
14 Sward	8/95	P	Willia
15 Peterson	9/95	P	Fritz
16 Olson	10/95	P	Heidepriem
17 Harmon	10/95	P	Colwill
18 Fine	10/95	P	Peterson
19 Chester	10/95	P	Cook
20 Youngblade	10/95	P	Hanks
21 Price	1/96	P	Fitzgibbons
22 Hesco	3/96	P	Roby
23 Swett	6/96	P	Nooney
24 Bunkofske	8/96	P	Barry
25 Moench	8/96	P	Jensen
26 Dorso	8/96	P	Myers
27 Didier	9/96	P	Swedlund
28 Baca	11/96	P	Eiseland
29 Langten	11/96	P	Day
30 Jones	2/97	P	Johnson,R
31 Davis	2/97	P	Head
32 Schweitzberger	5/97	P	McMahon
33 Alexander	6/97	P	Duffy
34 Stopkotte	10/97	P	Busick
35 Sletten	11/97	P	Binger
36 Cole	11/97	P	Morris
37 Wolcott	1/98	P	Johnson

38 Hayes	2/98	P	Eiseland
39 Elverude	3/98	P	Merkle
40 Gestring	4/98	P	Busick
41 Harvey	5/98	P	Killinger
42 Huron Kitchen	5/98	P	Janklow
43 Dickerson	5/98	P	Durkin
44 Beisch	8/98	P	Turbak
45 Fox	8/98	P	McCallister
46 Grunewald	9/98	D	Wheeler
47 Blair	9/98	P	Gleason
48 Balzer	9/98	P	Hertz
49 Peterson	9/98	P	Bridgeman
50 McLarty	12/98	P	Bottaro
51 Jurgensen	2/99	P	Johnson
52 Lippon	3/99	P	Barry
53 Praus	3/99	P	Greenwood
54 Kvols	3/99	P	Harmelink
55 McConnell	7/99	P	Hoy
56 Samaniego	7/99	P	Brown
57 Schiller	7/99	P	Greenwood
58 KayStar	8/99	P	Moore
59 Dvorak	9/99	P	Christensen
60 Beliveau	11/99	P	Swedlund
61 Fox	11/99	P	Groves
62 Kenworth	11/99	P	Welsh
63 Bahr	12/99	P	Chozen
64 Pavel	12/99	P	Howey-Fox
65 Ferrell	2/00	P	Swanson
66 Gonzalez	3/00	P	Kline
67 Nemesio	3/00	P	Mahr
68 Davis	5/00	P	Domina
69 Dietrich	5/00	P	LaFleur

70 Big Stone Partners	7/00	P	Gerdes
71 Kolar	9/00	P	Mahr
72 Feldmann	10/00	P	Kube
73 Chick	1/01	P	Wilson
74 Carr	2/01	P	Anderson
75 Hopfinger	3/01	P	Groseclose
76 Bahr	7/01	P	Ribstein
77 Lear	7/01	P	Welter
78 Holzbauer	7/01	P	Meierhenry
79 Der Hogopian	11/01	P	Starovoytova
80 Ruden	1/02	P	Lessman
81 Norling	1/02	P	Foss
82 Fisherman	2/02	P	Hoy
83 Olson	2/02	P	Fox
84 Scott	6/02	P	Nasser
85 Burke	12/02	P	Cutler
86 Rhoads	12/02	P	Day
87 Voeltz	1/03	P	Casey
88 Clark	1/03	P	Sommervold
89 Kruse	2/03	P	Bjorkman
90 Markegaard	5/03	P	Johnson, Glen

Curriculum Vitae
April 2004

Randall E. Waldron, Ph.D.
Associate Professor of Economics
School of Business
University of South Dakota
Vermillion, South Dakota 57069-2390

Education

December, 1994 — Doctor of Philosophy in Economics, Vanderbilt University (Nashville, Tennessee)

Fields of Specialization: Industrial Organization, Economic Development, and Econometrics
Dissertation Title: "Market Foreclosure and Strategic Vertical Integration in Successive Oligopolies"

June, 1985 — Bachelor of Arts with majors in Political Science and Economics, Northwestern University (Evanston, Illinois)

Academic Experience

August, 2000 - Present
Associate Professor
Division of Economics, Decision Sciences, and Management Information Systems
University of South Dakota School of Business

August, 1994 - July 2000
Assistant Professor
Division of Economics, Decision Sciences, and Management Information Systems
University of South Dakota School of Business

Courses taught at the University of South Dakota
Introduction to Economics
Principles of Microeconomics
Principles of Macroeconomics
Economic Analysis
Monetary and Fiscal Analysis
Macroeconomic Theory
Special Topics: Game Theory and Strategic Interaction in Economics
Industrial Organization
Managerial Economics II (Graduate Program)

1992 - 1994	Academic Counselor, Learning Center, Vanderbilt University Responsible for implementation of study programs, tutoring, and individual counseling for students facing academic difficulties
1989 - 1993	Instructor/Graduate Teaching Assistant Department of Economics and Business Administration. Vanderbilt University *Courses taught at Vanderbilt* Principles of Microeconomics Principles of Macroeconomics Intermediate Microeconomic Theory
1988 – 1989	Graduate Research Assistant Department of Economics and Business Administration, Vanderbilt University

Scholarly Activity

Refereed Publications

Stuefen, Randall M and Randall E Waldron, "Proximity Feeding of Distiller's Grain to Cattle and Dairy Herds," South Dakota Business Review, Vol LX, No III (March 2002)

Waldron, Randall E , "Marriage and Other Prisoner's Dilemmas," Humanomics, Vol 16, No 1 (2000), pp. 26 – 34

Waldron, Randall E , "A Game Theoretic Approach to Teaching the Principles of Economics," Proceedings of the Second Annual Economics and the Classroom Conference at Idaho State University, March/April 2000, pp 132-137

Stuefen, Randall M , Dennis A Johnson, Randall E Waldron, and Wade E. Paulson, "Electricity Pricing in a Restructured Electric Power Industry," South Dakota Business Review, Vol LVII, No III (March 1999)

Johnson, Dennis A., and Randall E Waldron, "Price Discounts in the Pharmaceutical Industry· A Theoretical Analysis," Proceedings of the Global Awareness Society, San Francisco, CA, May 1996

Current Research

Waldron, Randall E , "Learning Optimal Strategies in Rapidly Repeated Games· Lessons from Rock/Paper/Scissors "

Johnson, Dennis A , and Randall E Waldron, "On the Equivalence of Rent and Common Ownership Externalities "

Presentations at Professional Conferences

Waldron, Randall E 'Teaching and Learning with Mixed Strategy Games," Fifteenth Annual Conference on Teaching Economics Instruction and Classroom Based Research, Pittsburgh PA (Robert Morris College), February 2004

Waldron, Randall E , "Learning Optimal Strategies in Rapidly Repeated Games," Economic Science Association, Pittsburgh, PA, June 2003

Waldron, Randall E , "Marriage and Other Prisoner' s Dilemmas " First World Congress of the Game Theory Society, Bilbao Spain, July 2000

Waldron, Randall E , "Teaching Oligopoly Using Cournot Competition Games " Eleventh Annual Conference on Teaching Economics· Instruction and Classroom Based Research, Pittsburgh PA (Robert Morris College), February 2000

Waldron, Randall E , "A Game Theoretic Approach to the Principles of Economics " Second Annual Economics and the Classroom Conference, Pocatello, ID (Idaho State University), March-April 2000

Waldron, Randall E , and Malika Rajan, "Learning Optimal Strategies in Rapidly Repeated Games· Lessons from Rock/Paper/Scissors " Missouri Valley Economic Association conference, Memphis TN, February 1999

Waldron, Randall E , and James G Sword, "Parents' Valuation of Children and the Calculation of Damages in Wrongful Death Lawsuits " Southern Economic Association Conference, Atlanta GA, November 1997

Brown, Ralph J , Dennis A Johnson, and Randall E. Waldron, "The Economics of Recycling A Case Study " Missouri Valley Economic Association conference, St Louis MO, February 1997.

Johnson, Dennis A., and Randall E Waldron, "The Economic Impact of Limiting Drug Price Discounts " Missouri Valley Economic Association conference, Memphis TN, March 1996.

Waldron, Randall E , "Incentives and Strategies for Vertical Integration in Successive Oligopolies " Southern Economic Association conference, New Orleans LA, November 1995

Waldron, Randall E , "Conditions and Practices Facilitating Supra-competitive Pricing in International Markets " South Dakota International Business Conference, Rapid City SD, October 1995

Other Professional Reports and Presentations

Stuefen, Randall M , and Randall E Waldron, "Proximity Feeding of Distiller's Grain to Cattle and Dairy Herds " Report prepared for the South Dakota Corn Producer's Council, 2001 Presentation also made to the Corn Producer's Council, August 2001

Presentation of new technology developed through a Governor's Grant for Teaching with Technology, Pierre SD, 2000

Presentation to the School of Business Faculty, "A Medley of Games Research Projects in Game Theory," Faculty Development Seminar, 1999

Stuefen, Randall M , Dennis A Johnson, Randall E. Waldron, and Wade Paulson, Electricity Pricing In A Restructured Electric Power Industry Report prepared by the Business Research Bureau for the Rural Electric Association of South Dakota, delivered at the annual REA meeting, Pierre SD, January 1999 Full report available on the Internet at http //www usd edu/brbinfo/brb_research/publications htm

Presentation to the School of Business Faculty, "On Externalities and Rent. Miracles and Markets," Faculty Development Seminar, 1998

Brown, Ralph J , and Randall E Waldron Presentation of the results of a study, "The Economics of Recycling," at the Conference on Solid Waste Disposal, Omaha NE, October 1997 A similar presentation was made to the Joint Powers Solid Waste Authority for the cities of Vermillion and Yankton, SD, in August 1997

Presentation to the Social Science Consortium Conference for teachers, Sioux Falls SD, October 1996

Presentation to the School of Business Faculty, "Why Game Theorists Won the Nobel Prize in Economics," Faculty Development Seminar, 1995

Book Reviews

Waldron, Randall E., Review of R. N. McCauley, J. S Ruud, and F. Iacono, Dodging Bullets: Changing U S. Corporate Capital Structure in the 1980s and 1990s, MIT Press, 1999, in The Journal of Economics, 26·2, Fall 2000.

Waldron, Randall E , Review of N. R. Lamoreaux and D M G Raff, eds., Coordination and Information· Historical Perspectives on the Organization of Enterprise, University of Chicago Press, 1995, in Review of Industrial Organization, 11·141 - 143, 1996

Waldron, Randall E., Review of K. Binmore et al., eds , Frontiers of Game Theory, MIT Press, 1993, in The Journal of Economics, 21·2, Fall 1995.

Honors

Dean's Certificate of Achievement in Recognition of Outstanding Teaching, Vanderbilt University August, 1992

Rendigs Fels Award for Excellence in Teaching, Vanderbilt University May, 1992

Grants

Investment Travel Program Grant, Spring 2001, in support of travel to the National Conference on Undergraduate Research $500

Grant for Incorporating International Components in Courses, Fall 2000 $300

Grant for International Travel, Summer 2000, in support of travel and participation in the First World Congress of the Game Theory Society, Bilbao Spain $1200

Governor Janklow's Faculty Awards for Teaching with Technology, Summer 1999, in support of the proposal, "Redesigning Principles of Microeconomics for Interactive Learning " $18,693

Faculty Development Grant for Educational Experience, Summer 1996, in support of the proposal, "Faculty Participation in the European Study Tour " $1950

Siouxland International Project Grant, in support of presentation at the International Business Conference, Rapid City SD, October 1995 (noted above under presentations) $250

Professional consulting services (in addition to published reports above)

Consultant to the Joint Powers Solid Waste Authority of Vermillion and Yankton, 1996 - 1997 This uncompensated *pro bono* work was done as a service to the community

Consultant to the state of South Dakota in antitrust litigation involving milk price fixing, 1996 - 1997 This was paid work (at below market rates) which resulted in a favorable settlement for the state, and involved calculation of damages and distribution of the settlement to S D school districts

Consultant to the plaintiff in civil antitrust litigation involving alleged market monopolization in the home health care industry, 1995 - 1998

Service to the Economics Profession

Discussant and session chair, Missouri Valley Economic Association conference, Memphis TN, February 1999

Discussant and session chair, Missouri Valley Economic Association conference, St Louis MO, February 1997

Discussant, Missouri Valley Economic Association conference, Memphis TN, February 1996

Discussant, Missouri Valley Economic Association conference Kansas City MO, February 1995

Review of paper for the Public and Nonprofit Division of the Academy of Management, February 1999

Review of forthcoming textbook, Games of Strategy by Avinash Dixit and Susan Skeath

Service to the University

Chair, University Senate Learning Resources Committee, Library Division, 1997 - 2001

Member, University Senate Educational Resources Committee, Library Division, 1995 - 2001

Member, Board of Directors, USD Book and Supply, 1998 - present

Faculty Advisor, Campus Crusade for Christ, 1996 - present

Member, Proposal Review Panel, University Research Council, 1999 - 2000

Member, Faculty Screening Committee for "Who's Who among American College and University Students," 1997

Faculty Sponsor, Economic Policy Forum, an annual event in which students from Economics 202 organize a public forum and ask questions of a panel of expert economists, 1996 - present

Presentation to Advanced Placement calculus students, Vermillion High School, "Using Calculus in Economics," May 2001

Director for student (Chad Schuldt) in Technology Fellow Program, 2000 – 2001.

Faculty Consultant, Youth Business Adventure, Summers of 2000 and 2001

Director for student (Ruth Mangelsen) Ideafest presentation, Spring 2000

Regional Judge, National Council on Economic Education curriculum design competition for high school teachers, Minneapolis MN, Fall 2000

Judge, Federal Reserve Bank of Minneapolis essay contest for high school students, Spring 2000

Panelist, Business School Forum, "Will the Euro Replace the U S Dollar as World Currency?" 1999

Presentations to the Phi Delta Theta Fraternity, "Making Better Grades," Spring 1999 and Spring

2000

Presentation to the TTD 785 Delivery Systems class, "Distance Delivery Courses," March 1998

Presentation to the Business Ethics class, "Ethical Decisions in Economics," February 1996

Presentation to social studies students, Vermillion High School "The Competition Game," December 1998

Service to the School of Business

Chair, School of Business Promotion and Tenure Committee, 2001 – present

Member, School of Business Promotion and Tenure Committee, 2000 – present

Member, MBA Admissions Committee, 2001 – present

Member, School of Business Curriculum and Instruction Committee, 1999 - present

Member, School of Business Graduate Curriculum and Instruction Committee, 1995 - 1999

Chair, School of Business C & I Subcommittee on the Residency Opportunity for MBA students, 1997

Member, School of Business Committee on Assessment for the MBA program, 1997 - present

Presentation to faculty at the Center for Instructional Design and Development, February 1998

Member, School of Business Graduate Grievance Committee, 1999 - present

Faculty participant in the European Business Study Tour, traveling to the Netherlands, Germany, Belgium and France with students, 1996

Faculty co-leader of a tour of Winnipeg, Manitoba, with students from the Delta Sigma Pi business fraternity and the International Business class, 1996

Coordinator, School of Business Faculty Development Seminars, 1999 - present

Service to the Economics Department

Chair, Search Committee for economics position, 2000 – 2001

Member, Economics Scholarships Selection Committee, 1995 - present

Development of graduate work in economics including revision of the MA in economics program, the Ed D in economic education, and proposals for an economics option in the MBA program, and a Ph D in economics program, 1995 - 1996

Promotion of the Economics undergraduate major including development of a departmental brochure, survey of economics students, and participation in the Political Economy Club

Thesis/Graduate Examination Committees (Member of 2)

James G Sword, master's thesis committee (MA in economics)

Li Sheng Su, master's examination committee (MA in economics)

Undergraduate Honors Thesis Committees

Ruth Mangelsen, "Experiments in Game Theory Testing for Nash Equilibrium in Business Competition Simulations " (Director)

Kathryn Koenders, "Measuring External Costs through Private Property Rights with Dynamic Analysis " (Committee member)

Amy Johnson, "Do People Learn Optimal Mixed Strategies in Rapidly Repeated Games?" (Director; research in progress)

Honor Society memberships

Beta Gamma Sigma, the Honor Society for AACSB accredited business schools

Professional memberships

Economic Science Association, 2004 - present

National Association for Business Economics, 2002 – present

American Economic Association, 1993 - present

Game Theory Society, 2000 - present

Missouri Valley Economic Association, 1995 - 2002

Southern Economic Association, 1993 – 1999

WADE D. DRUIN

420 Pinehurst Ave ♦ Vermillion, SD 57069 ♦ (605) 624-1080 (H) ♦ (605) 677-5287 (W) ♦ wdruin@usd edu

EMPLOYMENT INFORMATION

Director **November 2002 to Present**

Business Research Bureau, Vermillion SD

Provide managerial direction and leadership to the various divisions and activities under the control of the Business Research Bureau along with providing strategic and management support to the University of South Dakota and the School of Business

- Development and supervision of staff
- Administration of seven separate programs
- Preparation, review, and administration of grants and contracts
- Identify, apply for, bid, and manage applied research opportunities
- Responsible for developing and implementing strategic plan
- Direct control over the budget and fiscal activities of the Business Research Bureau and its divisions
- Public relations representative for the Business Research Bureau
- Member of the School of Business's management team

State Director **March 1998 to November 2002**

Small Business Development Center, Vermillion SD

Provide managerial direction and leadership to execute the missions and budgets of the Small Business Development Center in order to promote the economic development of the State of South Dakota

- Assist staff with customer service and problem resolution issues
- Provide training to staff and other external organizations and individuals
- Perform networking and public relations role for the Small Business Development Center
- Negotiate and prepare annual cooperative agreement with the Small Business Administration
- Prepare and oversee the annual statewide budget of 1 2 million dollars
- Oversight of all statewide expenditures
- Management of the statewide information system to ensure compliance with policy and regulation
- Work with subcontractors to ensure effective customer service delivery
- Directly and indirectly, hire and supervise staff of 14

Regional Director **May 1991 to March 1998**

Small Business Development Center, Pierre, Watertown and Sioux Falls, SD

Provide managerial and technical assistance to numerous businesses

- Business, financial and marketing plans
- Loan applications (SBA, Bank, BED, Planning District, etc)
- Financial analysis and forecasting (income statement, cash flow, balance sheet, break-even and ratio analysis)
- Provide direction with accounting and bookkeeping
- Business structuring (Corporate, Partnership, Limited Liability and Sole Proprietorship)
- Business valuations (sale and purchase)
- Assist in formulating workout strategies
- Conduct research (general and marketing)
- Present numerous seminars on various subjects
- Develop close working relationship with local and regional lenders
- Supervise and hire support staff

Assistant/Adjunct Professor **January 1994 to Present**
University of South Dakota, Vermillion, SD
Instruct various business courses to include

- Business Law 320
- Finance 310
- Independent Study

Lake Area Technical Institute, Watertown, SD
Instructed various business courses, to include

- Business Law
- Business Management
- Accounting 210 & 211
- Entrepreneurship
- Federal Taxation
- Auditing
- Marketing Research
- Sales
- Lending

Capital University Center, South Dakota State University and Northern State University, Pierre SD
Instructed various business courses, to include

- Business Law
- Business Management

Staff Judge Advocate (current rank of Lt. Col.) **April 1988 to Present**
U S Air Force and 114 Fighter Wing, Sioux Falls, SD
Responsible for implementing military justice and providing legal assistance

- Senior Judge Advocate with responsibility of managing the base legal office, comprised of two additional attorneys and two paralegals
- Report directly to and represent the base commander concerning various legal issues
- Assist members with military and civilian legal issues
- Received an excellent rating on a QAFE inspection from 12th Air Force
- Develop and implement a deployment program, which has been presented to 12th Air Force as a model
- Participate in activating several local reserve units for Operation Desert Storm and Iraqi Freedom
- Air Force Commendation Medal, December 1993
- Air Force Achievement Medal, March 1992

Research Trainer **December 1995 to August 1997**
Thompson Publishing and Lawyers Cooperative, Watertown, SD
Independent contractor providing legal research training

- Train other attorneys and judges
- Extensive use of folios software
- Custom tailored training sessions to meet various levels of expertise
- Provide some hardware assistance

Attorney **June 1989 to May 1991**
Zimmer, Duncan and Deadrick, Parker, SD
Represent and assist numerous clients with legal problems and issues

- Specialize in business-related issues such as tax, bankruptcy and business association law
- Trial and discovery experience
- Research and draft numerous pleadings, briefs and memos covering a wide range of issues
- Assistance with supervision of support staff
- Favorably resolved numerous cases for the client through litigation or settlement
- Consistently billed between 30 and 35 hours per week
- Implementation of computerization of several office functions, including billing, research, bookkeeping and form generation

Tax Consultant **June 1988 to June 1989**
Delloitte, Haskins and Sells, Minneapolis, MN
Represent and assist clients with numerous tax issues
- Concentration in the corporate and partnership areas
- Formulation of tax projections to assist in liability minimization and deferral
- Performs legal research to find and implement tax reduction strategies
- Perform compliance work

BUSINESS INTEREST

CEO, Owner and Founder **June 1999 to January 2004**
Bluff Construction, Inc , Sioux Falls and Vermillion, SD

Owner, Managing Member **April 1997 to Present**
Druin Farms, LLC, Volin, SD

EDUCATION

Juris Doctor **May 1988**
University of South Dakota School of Law, Vermillion, SD

Bachelor of Science in Business Administration **May 1985**
University of South Dakota, Vermillion, SD
Emphasis in management and accounting (Eligible to take CPA exam)

Military Education
- Squadron Officer School (SOS), in residence, November 1994
- Judge Advocate Staff Officer Course, Maxwell AFB, AL, December 1989
- Army Boot Camp and Advanced Individual Training, Fort Sill, OK, Summer 1983

LICENSES/CERTIFICATIONS
- Licensed attorney, admitted to the South Dakota State Bar, September 26, 1988
- Licensed to practice in the U S District Court, September 18, 1989
- Licensed to practice in the U S Court of Military Appeals, December 4, 1989
- Commissioned Officer, U S Air Force, March 18, 1989
- Certified Economic Development Finance Professional, National Development Council, May 11, 1999

COMMUNITY INVOLVEMENT/PUBLIC SERVICE
- Volante Publications Board of Directors Member
- USD Research Council Member
- Family Business Initiative Board of Directors Member
- Political Volunteer
- Past Chamber of Commerce member
- Church Volunteer

Consulting services to assist the State of North Dakota's Public Service Commission in its investigation of Northern States Power's gas rate increase request

a proposal by London Economics International LLC

December 5, 2004

RECEIVED
DEC - 6 2004
ND PUBLIC SERVICE COMMISSION

LONDON ECONOMICS

London Economics International LLC ("LEI") is uniquely qualified to provide advisory services to the State of North Dakota's Public Service Commission ("NDPSC") in relation to its investigation of Northern States' Power's gas rate increase request. LEI has performed extensive consulting and advisory work in the Midwest for a variety of power sector parties, including regulatory bodies, IPPs, developers, utilities, and electricity consumers. We have a thorough understanding of regulated tariff analysis and valuation, as well as familiarity with the regulatory framework for natural gas in North Dakota. London Economics has extensive experience working with both private sector investors and regulators on rate-setting and rate-evaluation issues. London Economics staff have both the appropriate academic credentials and sufficient industry experience to present highly credible testimony regarding the fairness and reasonableness of Northern States' power's rate increase.

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5 APPENDIX A: TEAM RESUMES 21

5 1 AJ GOULDING, PRESIDENT .
5 2 BRIDGETT NEELY, SENIOR CONSULTANT
5 3 ANIA KARWOWSKA, RESEARCH ASSOCIATE

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Proposal
by London Economics International LLC
12/06/2004 CC Comm Legal PUD (4) Mike

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contact
AJ Goulding/Bridgett Neely
617-494-8200
info@londoneconomics com

1 Understanding the assignment

The North Dakota Public Service Commission ("NDPSC") is seeking proposals from outside advisors with regard to its investigation of Northern States Power Company's ("NSP") requested rate increase for its natural gas service in North Dakota While NSP is seeking a 1.8% increase in overall gas revenues, this increase could have a disproportionate impact on residential customers according to NSP's proposed allocation of costs.

The NDPSC is responsible for regulating the profits and rates of utilities in North Dakota. Its objective is to provide utility stockholders with a rate of profit similar to what could be earned in a competitive market situation (with similar risks) while providing an acceptable safe and reliable quality of service at a reasonable and just price that end consumers can afford.

The NDPSC is seeking support to evaluate the overall reasonableness of NSP's rate increase request. Thus, the tasks in this assignment will be to investigate, analyze, and provide testimony regarding the fairness and reasonableness of NSP's proposed rate base, its anticipated cost of capital, its regulated net income, and rate design among customer classes. The consultant would conduct relevant research pertaining to this topic, analyze NSP's filings, prepare written testimony, provide oral testimony, assist in the preparation of NDPSC staff for cross-examination of NSP's witnesses, and assist NDPSC staff in writing the proposed Finding of Fact.

The timing for the project has already been established by NDPSC. The investigation and submission of written testimony must be completed by March 1, 2005 The technical hearing will be scheduled for mid to late April 2005.

We understand that the process will evolve. Thus, the staff effort we have assigned to this work effort is flexible. In order to ensure sufficient coverage and quick turn-around of any unanticipated requests, we will allocate a multi-person team to this project We will aim maintain the maximum level of availability required by NDPSC through April 2005, or until the completion of the technical hearing.

2 Presentation of the London Economics team

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and electricity and gas distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, the firm has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide.

Why London Economics?

- ***Credibility*** arising from having advised both regulators and private investors on tariff issues
- Experience with tariff modeling across multiple ***North American and international*** jurisdictions
- Staff educated at highly reputable institutions and skilled ***independent*** quantitative analysis
- Ability to provide analysis that is clear and ***defensible***

2.1 Key qualifications

2.1.1 Overview of LEI relevant expertise

London Economics has performed a number of engagements that are directly relevant to this assignment. In addition to our experience working on tariff-setting and tariff-based asset valuations, we have also worked on tariff design issues as well as assessments of tariffs from the point of view of the end-consumer's willingness and ability to pay. One of LEI's key strengths is our ability to provide independent, unbiased advice with sound grounding in the basic principles of economics and finance to both regulatory bodies and to private sector clients. We believe that the fact that we advise large companies on asset valuation issues and tariff negotiations adds to our credibility when addressing regulators on the needs of investors.

Experience with tariff setting and evaluation – LEI has broad experience helping to design and adjust utility tariffs, including testimony to regulatory bodies regarding such tariffs. In addition, LEI has supported private sector actors in valuation exercises to determine the value of assets dependent solely on tariffs as their revenue stream. Finally, LEI has assessed end customers' ability and willingness to pay in the wake of tariff adjustments and provided testimony on this issue to public authorities.

Experience providing expert testimony to public bodies – LEI has experience providing written and oral testimony to regulatory and public authorities regarding its analysis. Our testimony has covered topics ranging from support for tariff design to justification for tariff and rate of return adjustments to contractual disputes. LEI has provided expert testimony to a variety of regulatory and public authorities in the US and abroad, including Federal Energy Regulatory Commission ("FERC"), Massachusetts Attorney General's Office, Connecticut's Department of Utility Control, Ontario Energy Board, and Alberta Department of Energy.

Comprehensive knowledge of the Midwestern energy sector – The team has been active in Midwestern energy markets, monitoring ongoing regional and local developments, modeling wholesale and retail power market dynamics, and assessing and evaluating assets and contracts for various clients, as well as retail supply alternatives. Among the topics we have examined are tariff design, gas market structure, bidding rules, ancillary services markets, congestion management arrangements, provider of last resort frameworks, the evolution of competitive wholesale and retail markets, market power mitigation provisions, and governance.

2.1.2 Detailed relevant project experience

The following are a list of projects that London Economics and assigned team members have conducted in recent years that demonstrate our regional expertise in the Midwestern market and our functional expertise in tariff design and analysis, as well as our experience providing expert testimony. Specific team-member project experience is detailed in the team member resumes, which are provided in Appendix A, which starts on page 15.

Natural gas market experience

London Economics has extensive North American natural gas sector experience. The firm has been involved with issues ranging from reviewing the economic viability of new LNG terminals to an assessment of natural gas safety provisions. Staff have created complex pipeline netback models to assess the impact of new pipeline products on wellhead prices in particular supply basins. We have identified potential natural gas company acquisition targets, forecast natural gas prices in selected regions, and examined the impact of Federal programs such as the Section 29 tax credit for non-conventional fuels production on natural gas supply.

Tariff design and analysis

- *Support on ISO-New England's self funding tariff:* London Economics provided support for ISO New England throughout the design and submission to FERC of ISO New England's self-funding tariff. London Economics first defined the basic underlying economic principles for specifying the tariff, then showed how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, frequent interaction with stakeholders, and written testimony before FERC.

- *Tariff adjustment following merger:* For the Massachusetts Attorney General's Office, LEI advised on a number of issues related to just and reasonable rates and returns associated with the merger of two major natural gas distribution companies in Massachusetts. London Economics' analysis and testimony provided justification for increasing the share of merger savings attributable to consumers.

- *Tariff design for privatization of Romania's electricity distribution network:* London Economics designed a Performance Based Ratemaking ("PBR") tariff structure for Romania's electric distribution system, incorporating reasonable assurances of capital recovery for investors. The proposal included extension of the current regulatory regime for 2004, with tariff increases to reflect inflation and initial capital investments. Following 2004, a PBR regime in the form of RPI-X+K+Z would be implemented, in which RPI is a measure

of Romanian consumer price inflation, X a targeted level of efficiency, K represents approved increases to ratebase due to approved capital investments, and Z a parameter to account for extraordinary events.

- ***For a variety of structured finance transactions, assessed tariff structures in light of customers' willingness to pay:*** LEI supported equity investors in more than 20 transactions involving electricity, gas and water assets, many of which were distribution systems, with analysis regarding existing and forecast tariffs; part of our analysis focused on determining whether or not tariffs would exceed customers' ability and willingness to pay. In certain instances, we provided such analyses to relevant public and regulatory authorities in support of such transactions.

- ***Development of Performance Based Rates ("PBR") for the Ontario Energy Board ("OEB"):*** London Economics advised on the design of second generation PBR for electricity distribution companies. Tasks include examination of methods of quantifying total factor productivity ("TFP"), determination of the appropriateness of yardstick competition models, identifying service quality indicators, and exploring the role of demand-side management. London Economics staff performed extensive stakeholder interaction, constructing databases, and advised on a final draft plan. They also testified during associated regulatory proceedings.

- ***Reviewed and adjusted electricity distribution tariffs in Argentina:*** The Argentine regulatory authority for the electricity sector (ENRE - Ente Nacional Regulador de la Electricidad) awarded a contract for a tariff review of Edenor, a large utility serving the northern portion of Buenos Aires, to a consortium led by London Economics. The engagement entailed evaluating the performance of Edenor in the 1992-2002 tariff period; advising ENRE on international best-practice design of distribution tariffs; proposing a tariff setting methodology for the 2002-2007 tariff period; providing technical assistance in the analysis of information presented to ENRE by Edenor; proposing tariffs for the 2002-2007 tariff period; and assisting ENRE during public hearings on the proposed tariffs.

Expert testimony

- ***Written testimony regarding the appropriateness of proposed default supply rates in Western Pennsylvania:*** On behalf of an intervenor, we reviewed default supply arrangements proposed by the incumbent utility. This process included modeling of future market price outcomes, an assessment of prices available from marketers, a review of credit procedures, and an analysis of future market design changes.

- ***Written testimony to CT regulator regarding fairness of TSO auction process:*** London Economics supported the Connecticut Department of Public Utility Control in its monitoring of Connecticut Light & Power ("CL&P")'s auction process to procure 2005 and 2006 power generation supply for its standard service customers (peak annual demand of 5,000 MW); LEI participated in all aspects of the auction process to ensure that CL&P's affiliate, Select Energy, did not obtain an unfair advantage in the bidding process. LEI provided an affidavit to the CT regulator regarding its assessment of the auction process.

- *FERC 203 filings in support of a proposed asset acquisition:* London Economics has prepared support for FERC filings under section 203 of the Federal Power Act for several different clients related to the proposed acquisition of generation assets The applications show that the transaction is in the "public's interest" - primarily by showing that there are no unmitigated negative competitive effects stemming from the proposed transaction. LEI's objective in these filings has been to meet the specific analytical requirements of the market power tests required by FERC.

- *Expert testimony regarding contractual dispute in Thailand:* London Economics served as an expert witness in an arbitration case involving disputed contract amendments related to an IPP acquisition in Thailand. We analyzed the proposed damage claims presented by the opposing side and presented our assessment of damages arising from undisclosed changes. We provided in-depth support to the attorneys including research pertaining to the Thai power industry and petrochemical industry.

- *Expert testimony regarding expansion of Australian transmission grid:* London Economics prepared expert testimony and modeling on the impacts of interconnection expansion between New South Wales and South Australia in Australia in the context of a dispute over how the Australian Competition and Consumer Commission ("ACCC") should determine whether interconnections should or should not be entitled to a regulated revenue stream.

- *Expert testimony regarding payments to market participant:* LEI served as an independent expert under the National Electricity Code to determine the fair payment price for directions issued to a Code Participant. Essentially the directions were issued in relation to two sets of events: 1) the first set of events occurred over the period between 11 and 12 December 2002 and related to unusual weather events that prevailed at the time; and 2) the second event occurred on 28 December 2002 and resulted from the application of an intraregional constraint being applied to the transmission network.

Midwestern regional experience

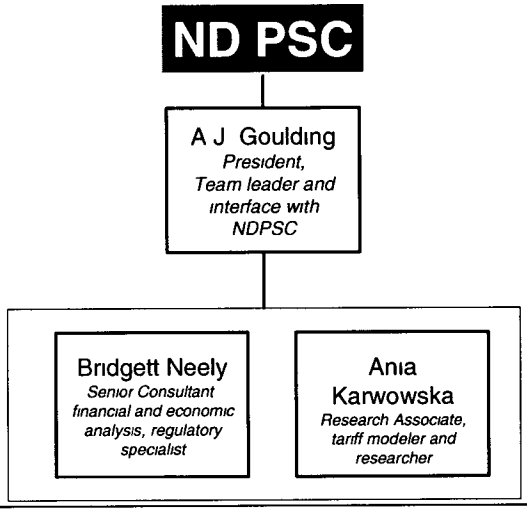
London Economics has conducted numerous projects in the Midwest, including the ECAR, MAIN, and MAPP regions. Such projects usually involve medium to long term price forecasts for the region under scenarios that reflect different outlooks on economics growth, fuel dynamics, and consumption and integrate information regarding new build and interconnection capacity. Many of our price forecasts have subsequently supported asset acquisition bids in these markets. In addition, London Economics is also publishing North American market briefings on all electricity regions in the US, Canada, and Mexico, including the MAPP region. These market briefings included detailed information on the region's regulatory regime, actors in generation, transmission, distribution, and supply, as well as tariff regimes for transmission and distribution. The market briefings also include two page state profiles as well.

2.2 Overview of LEI team, relevant experience and capabilities

Based on the requirements of the engagement, LEI has composed a strong consulting team for this engagement, as shown in the figure below. The team will be led by A.J. Goulding, the president of LEI. Additional named members of the LEI team include Bridgett Neely and Ania Karwowska. The team will be supported by additional research staff if needed. This team has experience tackling projects of this caliber and working on multiple issues in a time sensitive manner.

A.J. Goulding, President of LEI, will lead the LEI team for this project. A.J. specializes in regulatory economics and divestiture-related power sector asset valuation in the US, Canada, Asia, and emerging markets. A.J. has been involved in all of the firm's projects regarding tariff design and tariff assessment, and brings a breath of international and sectoral experience to this issue, having advised regulators across North America and abroad on tariff issues in the natural gas, power, and water sectors.

Figure 1. Overview of LEI team



The LEI team also includes Bridgett Neely, Senior Consultant, and Ania Karwowska, Research Associate. Bridgett has been actively engaged in several tariff setting projects, having designed and managed the regulatory model for the acquisition of two electricity distribution systems, as well as having assessed energy distribution system tariff regimes across North America and abroad. Ania also has significant experience modeling tariff regimes and will provide research and analytical support to the team.

Detailed resumes for each team member are provided at the end of this document in Appendix A, which starts on page 15.

2.3 Contact person for further information

Any future information or data requests regarding this response for proposals should be addressed to A.J. Goulding, c/o London Economics International LLC, 717 Atlantic Avenue, Unit 1A, Boston, MA 02111. A.J.'s office phone number is (617) 494-8200; fax number is (617) 494-4746; and email: ajg@londoneconomics com.

2.4 References

Please find below a short reference list for LEI. These individuals should serve to provide the NDPSC with an overview of LEI's dedication, professionalism, and technical expertise. Additional references are available on request.

Contact Name:	Dale McMaster
Company Name:	Alberta Electric System Operator
Company Address:	1800,700 4th Ave SW Calgary, AB T2P 3J4
Contact Telephone Number:	(403) 705-5202
Nature of Assignment:	Analysis of competitive sales processes, including entire spectrum of negotiated processes and open auctions; review of the advantages and disadvantages of clock auctions and recommendations for Balancing Pool, given the status of the market, anticipated dimension of bidders, and objectives of the Balancing Pool in divesting the derivative contracts under MAP II LEI also advised on the development of the reservation price for the contracts.

Contact Name:	Armando Perez
Company Name:	California ISO
Company Address:	P O Box 639014, Folsom, CA 95763-9014
Contact Telephone Number:	(916) 351-4444
Nature of Assignment:	Construction of a transmission investment evaluation framework for selecting and justifying large scale, economically-driven transmission investment in front of the California Public Utilities Commission.

Contact Name:	Elizabeth Howland
Company Name:	TXU
Company Address:	1601 Bryan Street, Energy Plaza, Dallas, TX 75201
Contact Telephone Number:	(214) 812-5477
Nature of Assignment:	Assessment of proposed market power mitigation rule changes by the staff of the Public Utilities Commission of Texas, including analysis of market rules, examination of wholesale market impact and efficiency considerations vis-à-vis bidding behavior and investment signaling. Principles of auction theory and contestable markets also applied. LEI's findings submitted as testimony in proceeding to the PUCT.

2.5 Additional documents requested by NDPSC

The additional documents requested by the North Dakota Public Service Commission are attached to this document.

3 Statement of Work

3.1 Introduction

The North Dakota Public Service Commission ("NDPSC") is investigating Northern States Power's ("NSP") gas rate increase request to ascertain its overall fairness and reasonableness Ensuring that NSP's costs are reasonable and that its cost allocation across customer classes is consistent with actual costs of service are crucial elements to this process. London Economics staff is very familiar with regulated tariff based assignments. We are also experienced at providing written and oral testimony to regulatory bodies based on our research and analysis. Section 3.2 provides a brief overview of main issues that need to be considered in the assessment of tariff increase requests. In Section 3.3, we provide an overview of our approach to the overall project and in Section 3.4, we provide a more detailed plan and discussion of methodology.

3.2 Context

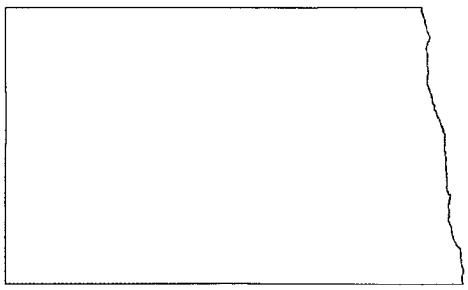
3.2.1 Gas supply in North Dakota

The natural gas sector remains regulated in North Dakota and there is no unbundled service for residential or small commercial customers in the state. The NDPSC is in charge of regulated all bundled rates for natural gas supply in the state and it regulates tariffs as per Chapter 49-05 of North Dakota Century Code.

In 2002, the state consumed 42,569 million cubic feet of natural gas. While 45% of this gas was consumed by industrial customers, the remaining 55% was consumed by the state's residential and commercial customers. The state has 109,000 residential customers and 16,000 commercial customers.

Northern States Power, a gas distribution utility owned by Xcel Energy, provides natural gas supply to two main service areas, as illustrated in the graphic below. Excel is a natural gas and electricity utility and operates in 11 Midwestern and Western states and has annual revenues of almost $8 billion. Xcel has 1.8 million natural gas customers.

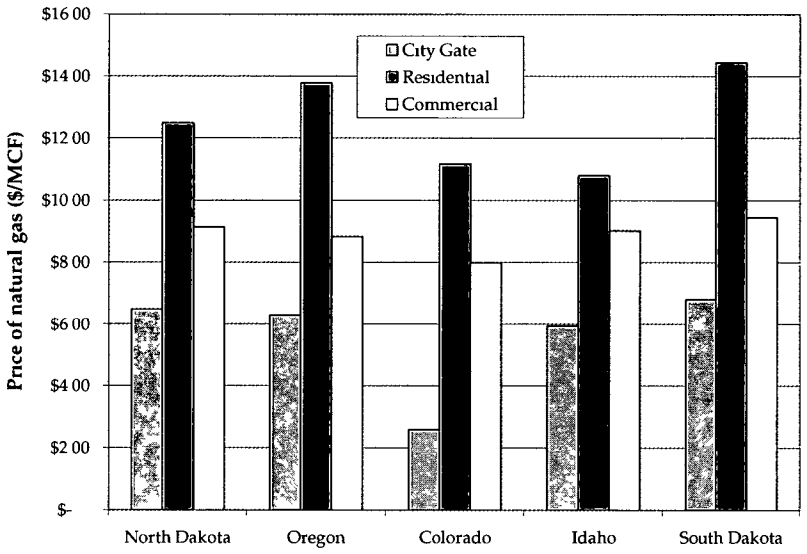
Figure 2. Northern States Power service territories in North Dakota



3.2.2 Gas tariffs

In the context of rising gas prices across the country, verifying and approving gas tariff increases is of increasing importance for state regulators, who must balance the needs of utilities to earn a reasonable profit margin on their activities with the imperative to give end-consumers safe and reliable gas supply at a fair, reasonable, and affordable price. Indeed, average city gate gas prices are now averaging about $6 per thousand cubic feet, as is illustrated in the graphic below, as compared to a historic range of $2 to $3 per thousand cubic feet. The impact of this doubling in gas cost is having a serious impact on residential customers, who are seeing their heating bills rise dramatically.

Figure 3. Comparison in natural gas prices



Source EIA data for August 2004

In this context, the request by distribution utilities for additional rate increases must be carefully evaluated and assessed in order to ensure that only those costs that are absolutely vital and reasonable are passed on to the consumer, and that the appropriate consumer class is charged for these costs.

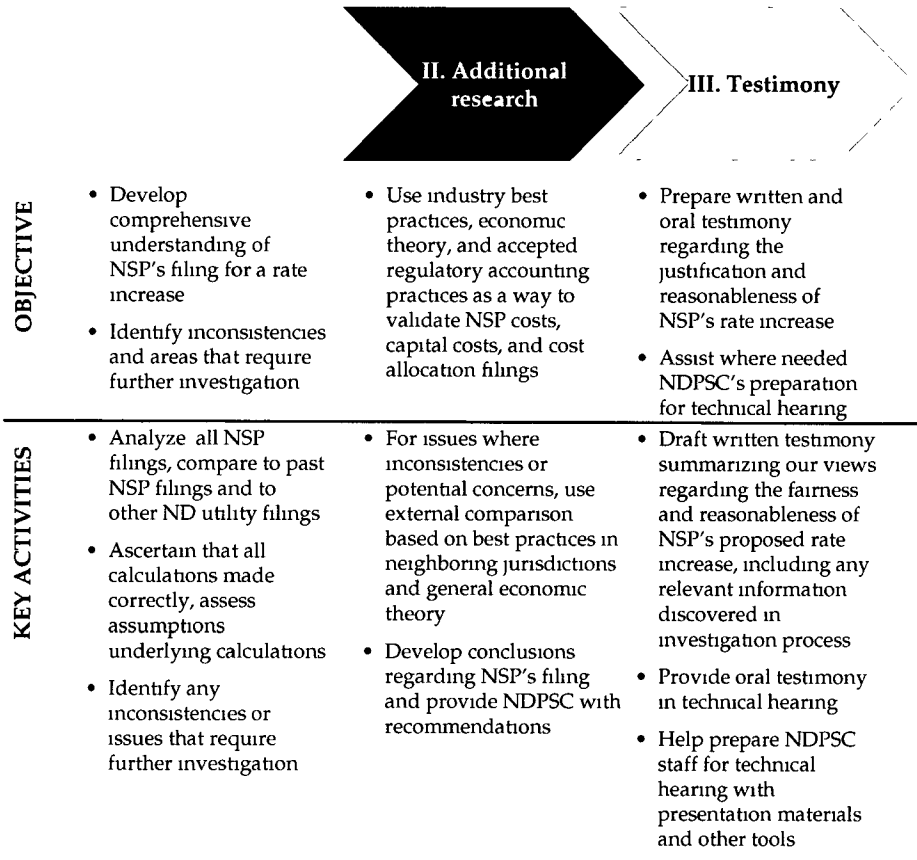
NSP is not the only North Dakota gas utility to have recently filed for a gas tariff rate increase. Indeed, in March 2004, Montana Dakota Utilities ("MDU") filed for a total rate increase of 2.8%, which would generate additional revenues in North Dakota of $3.3 million. MDU also filed for interim rate relief to generated additional annual revenues of $1.9 million. Like NSP, MDU proposed that all increases be channeled into the firm residential and commercial rate schedule and that no changes be applied to larger consumers. MDU's primary reason for its requested rate increase was increased operating expenses driven by increases in labor and benefit costs. In September 2004, following six months of hearings and deliberations, the NDPSC filled an order that MDU could receive interim rate relief resulting in annual revenues of $1.7 million and that its increase in its tariffs could result in a final annual revenue increase of not more than $2.5 million.

According to the NDPSC's Request for Proposal, NSP's total revenue increase request will result in a 1 8% increase in overall natural gas revenues. However, unlike MDU, the reason behind NSP's request is apparently due to investment related costs associated with meeting growth and revenue erosion caused by declining use per customer The increase in tariffs, as proposed by NSP, will fall largely on residential customers. Thus, assessing NSP's request will also require taking into consideration other social and economic issues such as population growth, per capital energy consumption, and changes in NSP's costs of service.

3.3 London Economics approach

Based our knowledge of the regulatory process and our experience with tariff modeling, we have segregated the work effort into three different phases of the procurement process. Our role as advisor to the NDPSC will vary depending on the phase of analysis. While we detail the tasks that we think are likely to be needed during each of the phases in Section 3.4, we are also used to working in a dynamic environment and responding to questions and client's needs as they arise. Our team, which is comprised of individuals with specific market and functional expertise, can rapidly coordinate in order to provide feedback or analysis to the NDPSC on an as needed basis. Thus, the details provided in the next section should only be taken as an indication of the tasks that are likely to be covered within the scope of our project.

Figure 4. LEI approach



3.4 Detailed methodology

We anticipate three distinct phases to this project, which are highlighted in Figure 4 above. These three phases involve an assessment of NSP's filing, an investigation into inconsistencies or areas of concern, and preparation for the technical hearing. In the subsections below, we address each of these phases individually.

3.4.1 Analysis of NSP filing

The first phase of work will entail assessing all of NSP's proposed rate increase filing in order to clearly understand the basis for NSP's rate increase request. Thus, we will analyze in detail NSP's costs for natural gas distribution in North Dakota and assess its allocation of these costs across the customer classes it serves, as well as the split between customer-related and energy-related costs. We will verify these filings with filings by NSP's parent, Xcel Energy, as well as with filings by NSP in its other jurisdictions (Minnesota and Wisconsin), to ensure that the data are consistent. We will carefully analyze NSP's calculations for its rate increase, ensuring that all calculations are indeed correct and assessing each of the assumptions underlying this analysis. In addition, we will compare NSP's filings with other North Dakota gas utilities (Great Plains Energy and Montana Dakota Utilities) to compare costs structures and cost allocation approaches. Finally, we will develop a list of inconsistencies and concerns that we think most pertinent to discuss with the NDPSC and to develop a priority list for issues to investigate.

3.4.2 Investigation (additional research)

During this phase, we will rely on our experience in tariff setting projects across the country and globally to help identify ways to double check any contentious figures provided by NSP. Using the list of priority issues developed in the previous phase, we will investigate each issue in detail using industry best practices, economic theory, and accepted regulatory accounting practices as a way to validate or question NSP's costs, capital costs, and cost allocations. For example, we will compare NSP's proposed cost of capital to other recent capital costs filed for gas distribution utilities across the US, especially those that have a similar population density and level of gas consumption as NSP's service territory in North Dakota. We could also examine NSP and Xcel's actual costs of debt to be certain that these are being accurately reflected in the cost of capital. Should cost allocation among customer classes be an issue, we can look at ratios of costs in other systems in order to be certain that NSP's proposal is indeed reasonable and just, given industry best practice. Finally, we will provide to NDPSC our conclusions regarding NSP's request for a rate increase as well as our recommendations regarding this filing.

3.4.3 Technical hearing (testimony)

The last phase is dedicated to the technical hearing, which will decide the rate increase. We will summarize our assessment and analysis into a written testimony which will be provided to the NDPSC by March 1, 2005. We will be happy to provide NDPSC with a preliminary draft of our written testimony and to respond to any comments NDPSC may have. We will then prepare oral testimony based on this written testimony for the technical hearing, which will be scheduled for mid to late April. Finally, we will also work with relevant staff within NDPSC to prepare for the

technical hearing, such as the cross examination of witnesses for NSP. Lastly, once the hearing has been concluded, we will help NDPSC prepare the proposed Finding of Fact document.

4 Pricing terms

Our estimated budget for the entire project totals $38,600 and includes all aspects of the investigation through the completion of the technical hearing. This allows for over 30 person days at our discounted US government hourly fee rates, as well as a budget of $5,000 for expenses. Expenses may include travel and lodging for trips undertaken at the NDPSC's request, data acquisition, and licensing and library fees, all subject to NDPSC approval. This amount is the maximum that we anticipate spending on expenses; we will provide NDPSC will receipts of actual expenses and will only bill through that amount Thus, the amount for actual expenses may be lower than the $5,000 that we have currently budgeted.

As per the RFP, we are amenable to only conducting one of the project phases, should the NDPSC so see fit. We have provided a breakdown of our professional fees by project phase. We would be happy to revise these estimates, should the NDPSC have specific tasks that it would like us to undertake.

Figure 5. Summary of not-to-exceed budget without prior approval of the NDPSC

Phase I	$11,200
Phase II	$8,800
Phase III	$13,600
Total professional fees	**$33,600**
Estimated expenses	**$5,000**
Total budget	**$38,600**

London Economics will invoice monthly for the work completed in the previous calendar month. The invoices will document the effort expended by the assigned staff (arranged by tasks and deliverables), the hourly rates, and the total incurred professional fees We will submit separate invoices for any expenses incurred during the course of the project on a monthly basis.

5 Appendix A: Team Resumes

5.1 AJ Goulding, President

EDUCATION: **MA, International Business, Columbia University**

BA, Economics, Earlham College

KEY QUALIFICATIONS:

In his role as president of London Economics International LLC, A J. Goulding manages a growing international consulting firm focused on finance, economic, and strategic consulting to the energy and infrastructure industries. In addition to serving as a sector expert in electricity and gas markets, his responsibilities include project management, marketing, budget and financial control, and recruiting Since 2003, A.J. has also served as an adjunct professor at Columbia University, where he teaches a course on electricity market design and regulatory economics.

A.J. specializes in regulatory economics and divestiture-related power sector asset valuation in the US, Canada, Asia, and emerging markets. He also advises major US and UK electric utilities on international business development strategy. A.J. is uniquely capable of assessing market design efforts from the standpoint of future private investors, identifying aspects that will enable the financing of new investment while at the same time providing economically-rational electricity prices. He is also particularly knowledgeable about the role of power marketers in creating specialized electricity risk management products and adding liquidity to wholesale power markets.

Among A.J.'s recent engagements have been a comprehensive review of the Romanian distribution sector, including tariff setting, distribution company valuation, and design of supply arrangements; advising Japanese utilities and banks on the implications of electricity sector reform; serving as an expert witness in a dispute related to IPPs in Thailand; leading advisory work on multiple innovative leasing and swap transactions related to network assets in Netherlands, Austria, and Australia; analysis of issues surrounding acquisitions of four major North American utilities/IPPs; and evaluation and evaluation and analysis of all aspects of the electricity market design process in Alberta and Ontario.

EXPERIENCE RELEVANT TO CURRENT PROPOSAL

- ***2nd generation PBR in Ontario:*** Led Cdn. $1.5 million engagement focusing on design of second generation PBR in Ontario Key components include estimating total factor productivity (TFP), determining appropriateness of yardstick competition, analyzing demand-side management programs in the context of PBR, and examining service quality indicators.
- ***Valuation of PPAs associated with IPPs in Thailand:*** As an expert witness in an arbitration case, A.J. quantified the change in value resulting from modifications to several PPAs associated with a power project in Thailand. Engagement included review of PPAs, evaluation of Thai power sector restructuring process, extensive modeling of financial aspects of PPAs, and assessment of financing alternatives; client won on all claims.

- *Advisory support for acquisition of two electricity distribution networks in Romania:* In support of an acquisition by a European utility, LEI provided input to the regulator and government for market design issues, including pass through of power costs, separation of distribution and retail activities, and Provider of Last Resort options.

- *Reviewed of regulatory and market developments in the electric power sector in the Philippines and in several key Caribbean countries:* Tasks included examining and valuing various IPP assets, creating long term tariff models for distribution companies, identifying potential purchasers of assets in the relevant countries, and defining strategic objectives associated with the assets. The engagement also included an analysis of the financial structure for asset purchases in emerging markets.

- *Evaluation of new transmission projects:* Co-led project on the cost-benefit analysis of new transmission projects proposed in Alberta that alleviate constraints between the northern and southern areas of the province. Applied probabilistic-based production cost modeling in conjunction with analysis of strategic bidding behavior to determine potential value and cost of projects. Framework for analysis based on LEI's ViTAL method, incorporating real options analysis and resolution of the generation versus transmission n investment coordination problem.

- *Due diligence associated with Ontario transmission and distribution assets:* applied detailed understanding of performance-based ratemaking concepts to advise on valuation and strategic considerations associated with a bid for the largest transmission and distribution company in Ontario.

- *Valuation and regulation of LNG facilities:* Assessed potential for combination of strategically situated LNG facility with US wholesale power marketer; for separate client, advised on third party access requirements for LNG facilities in the US and relevance to potential regulatory changes in Japan.

- *Workshop on performance-based ratemaking strategy:* For first stand-alone transmission company in North America, conducted day long workshop on issues associated with PBR, including the types of PBR and which one is most appropriate for what type of company, the sources of efficiency gains observed in other transmission companies worldwide, and the impact of performance standards on profitability and flexibility.

- *Development of regulatory and financing strategy for transco:* For first stand-alone transmission company in North America, evaluated key transaction parameters, assessed allowed ROE, proposed strategy for attaining favorable incentive rates, and helped to identify potential cost savings.

- *Critiquing and improving electricity market structure in Alberta:* For market institutions and regulators in the Canadian province of Alberta, performed extensive analysis of current industry market structure, including role of Power Pool, Transmission Administrator, Market Surveillance Administrator, the Scheduling Coordinator, and the Balancing Pool. Directed detailed analysis of market power issues associated with divestiture of specific assets and advised on particular market rules to ameliorate strategic behavior.

5.2 Bridgett Neely, Senior Consultant

EDUCATION: **MA, International Business, Columbia University**

BA, International Relations, Tufts University

KEY QUALIFICATIONS:

In her role as a Senior Consultant at London Economics, Bridgett specializes in business and market strategies for all types of infrastructure actors in a post deregulation era, including utilities, IPPs, financial institutions, grid operators, institutional actors and industrials. She has been involved in numerous projects that involve modeling of regulated tariffs for gas, electricity, and water utilities, and has also provided regulatory bodies with expert testimony and advice on topics including tariff design and levels, best practices regarding procurement, and validation of tariff components.

RECENT PROJECTS RELEVANT TO CURRENT PROPOSAL:

- ***Tariff and regulatory asset base modeling***: In multiple assignments related to leasing or acquisition of gas, electricity, and water distribution company assets in Austria, Germany, and the Netherlands, created complex financial models examining the impact of future tariff changes, efficiency gains, system load growth, and capital expenditures on current distribution company valuations

- ***Support to CT regulator regarding auction for TSO supply:*** For the Connecticut Department of Utility Control ("CT DPUC"), helped to monitor Connecticut Light & Power's ("CL&P") competitive procurement process for its Transitional Standard Offer for 2005 and 2006, entailing 5,000 MW of peak demand for each year; provided an affidavit to the CT DPUC regarding CL&P's management of the auction process and the fairness of the process.

- ***Valuation of numerous infrastructure assets in power and water sector in Western Europe:*** For cross border lease transactions, assessed the marketability of the transaction given its current contractual structure and the likely evolution of the sector in the region; valued the assets using the prevailing and expected regulatory structure and conducted a Net Benefit Analysis of the transaction from the point of view of the contractual counterparty.

- ***Advisory support for acquisition of two electricity distribution networks in Romania:*** In support of an acquisition by a European utility, LEI provided input to the regulator and government for market design issues, including pass through of power costs, separation of distribution and retail activities, and Provider of Last Resort options.

- ***Managed production of London Economics Press North America publication:*** Bridgett manages the firm's market briefings and is currently completing the 200 page publication that covers all North American electricity regions, which covers regulatory conditions, market design, and a description of key actors.

- ***Benchmarking of ancillary services and transmission loss procurement by grid operators:*** For a large European grid operator, international benchmarking on procurement

procedures, pricing structures, marginal costs; provided advice on which approaches most effective for client's needs and in terms of economic efficiency.

- ***Assessed auction formats and assessed auction outcome in function of regional market dynamics:*** LEI researched and monitored auctions of supply obligation (for example, NJ's BGS) and sale of virtual capacity (such a Alberta's MAP II auction of dispatchable rights and EdF's sale of capacity) on behalf of US investors looking at investment opportunities in similar transactions internationally. Provided detailed qualitative and quantitative analysis of auction outcomes compared to relevant regional market dynamics

- ***Benchmarking of post-deregulation energy strategy of world's largest steel manufacturers***: For a multinational steel manufacturer confronting the acquisition of many global production sites, identification of best practices; determination of developments needs; assessment of advantages and disadvantages energy strategies, including impact on ROCE.

5.3 Ania Karwowska, Research Associate

EDUCATION: **BA, Economics, Lawrence University**

KEY QUALIFICATIONS.

Ania Karwowska is a Research Associate with London Economics. She has conducted numerous projects that involve modeling of regulated tariffs for gas, electricity, and water assets and has researched tariff regimes around the world extensively. Recently, Ania was involved in transactions evaluating private sector participation in the water and wastewater sectors. The scope of the projects encompassed modeling of cash flow, tariff setting, projection of reasonable tariffs under performance-based ratemaking regime, and other financial modeling techniques.

RECENT PROJECTS RELEVANT TO CURRENT PROPOSAL:

- ***Financial modeling of European distribution company revenues:*** created distribution company financial models for targets in Austria, Germany, Netherlands, North America, and elsewhere. She has researched the appropriate cost of capital, examined the relationship between load growth and future macroeconomic drivers, and mastered the art of representing tariff conditions in spreadsheet models
- ***Review of NERC regional electricity markets in United States:*** reviewed the current state, regulatory market developments, and the ongoing challenges arising in the NERC regions of the United States electricity market
- ***Modeling of water and wastewater tariffs in Austria, Germany, and Belgium:*** structured financial modeling environment to project reasonable tariffs of a water and wastewater utility in a transition from public to private ownership with attention to reasonableness of post-privatization rate shock. The tariff design incorporated incentive mechanisms borrowed from worldwide performance-based regulation best practice. Advised on provision of government subsidy as a way of encouraging private sector participation in the water and wastewater utility sector designed to address legal limitations on the ability of private operators to recover of the investment through tariffs.
- ***Review of regulatory and market developments in the electric power sector in the Philippines and in several key Caribbean countries:*** tasks included examining and valuing various IPP assets, creating long term tariff models for distribution companies, identifying potential purchasers of assets in the relevant countries, and defining strategic objectives associated with the assets. The engagement also included an analysis of the financial structure for asset purchases in emerging markets
- ***Examination of the success of UK PBR initiatives:*** as a foundation for advising on the acquisition of a distribution company in a third country, reviewed PBR regimes in the UK and their impact on the profitability of companies there. This information was then used to assess the risks to distribution system owners in other countries should similar regimes be established there

- ***Survey and analysis of allowed ROE and WACC for electricity distribution companies across Europe:*** as a part of engagement involving acquisition by a European utility of two electricity distribution companies in Romania, Ania conducted a comprehensive review and analysis of allowed rates of return (ROE) and weighted average cost of capital (WACC) and its components adopted by Eastern European electricity distribution companies
- ***Financial modeling of supply contracts:*** to determine potential liability for an acquirer, reviewed a number of long term supply contracts to municipal utilities in New England. She examined the term of the contracts, potential forward electricity pricing, the potential to break the contracts, and current cost of capital issues to determine the risks associated with the contracts



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www londoneconomics com

December 2, 2004

Illona A. Jeffcoat-Sacco:
Executive Secretary
North Dakota Public Service Commission
State Capital, 12th Floor
Bismark, North Dakota 58505-0480

Dear Ms Jeffcoat-Sacco:

London Economics International LLC ("LEI") do not believe that any of our current client relationships would present a conflict of interest to this project. We are not currently working for the State of North Dakota's Public Service Commission ("NDPSC") or companies and affiliates regulated by NDPSC. Nor, to our knowledge, do any of our current clients have financial interest in these companies. Though from time to time, we are engaged on projects by energy-related companies located in the Midwest and power marketers transacting across the Midwest, we do not believe that such projects could pose any conflict of interest to this assignment.

LEI maintains strict internal procedures to avoid commingling of client data and assumptions. Furthermore, staff on this project will not be involved with any future engagements related to the Midwest market were such an engagement to result in a conflict. For example, we will refrain from advising any other participants in this auction, including potential bidders.

LEI is an equal opportunity employer. We have a diverse group of individuals, providing us with a unique project perspective. Of the thirteen full-time employees and senior advisors, nine are women. Almost a quarter of our staff is Asian. We are committed to maintaining a diverse work force and actively seek out employees with diverse backgrounds and experiences. Employees are promoted without regard to their ethnicity or gender.

A J. Goulding
President
London Economics International, LLC

CERTIFICATE OF INSURANCE

To be completed by Agent or Broker

THIS CERTIFICATE IS ISSUED TO

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
12th Floor, 333 Dunsmuir Street, Vancouver, B.C. V6B 5R3

CONTRACTOR NAME | CONTRACT/PURCHASE ORDER NO.

CONTRACTOR ADDRESS

And certifies that policies of insurance as herein described have been issued to the insured(s) named below and are in full force and effect.

INSURED	NAME: London Economics ADDRESS: 717 Atlantic Ave, Unit 1A, Boston MA 02111
OPERATIONS INSURED	PROVIDE DETAILS

TYPE OF INSURANCE	COMPANY NAME AND POLICY NO.	EXPIRY DATE Y	M	D	LIMIT OF LIABILITY/AMOUNT
COMMERCIAL GENERAL LIABILITY (INCLUDES CROSS LIABILITY, SEVERABILITY OF INTEREST, AND NON-OWNED AUTOMOBILE)	HARTFORD INS 08SBAPM4818	05	05	23	INCLUSIVE LIMITS $2,000,000
AUTOMOBILE LIABILITY (OWNED OR LEASED VEHICLES)	HARTFORD INS 08SBAPM4818	05	05	23	PRIMARY $ 1,000,000 EXCESS $
UMBRELLA LIABILITY					LIMITS $ EXCESS OF $
COURSE OF CONSTRUCTION (BUILDERS ALL RISK)					LIMITS $
PROPERTY	HARTFORD INS 08SBAPM4818	05	05	23	DETAILS Business Personal Property $ 49,500 $
Prof Liability OTHER	NATIONAL UNION TBD	05	10	19	DETAILS PROF LIMIT $ 3,000,000 $

These policies comply with the insurance requirements of the contract documents, and/or contract/purchase order with BC Hydro. It is understood and agreed that where required by the contract documents, and/or contract/purchase order, BC Hydro has been added as an additional insured and that thirty (30) days' written notice of cancellation or negative material alteration of or to any of the insurance policies listed herein, either in part or in whole will be given by the insurers to the holder of this certificate.

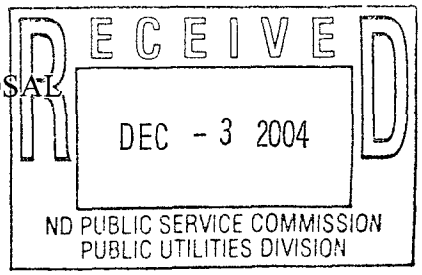
SIGNED BY THE CONTRACTOR | PRINT NAME | DATE SIGNED Y M D

SIGNED ON BEHALF OF THE UNDERWRITERS / INSURERS | PRINT NAME AND AGENCY/BROKERAGE NAME | DATE SIGNED Y M D

Kristen Dellbrull
Risk Strategies Company
04 11 11

RESPONSE TO

REQUEST FOR PROPOSAL



FREE STATE SYNERGIES

REVENUE REQUIREMENT REVIEW
NORTHERN STATES POWER

CASE NO. PU 04-578

ON BEHALF OF NORTH DAKOTA PUBLIC SERVICE COMMISSION

DECEMBER 6, 2004

20 PU-04-578
Proposal
by Free State Synergies
12/06/2004 CC Comm Legal PUD (4) Mike

James M. Proctor
4803 Hallbrook Dr.
Lawrence, KS 66047

December 6, 2004

Ms. Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismark, North Dakota 58505-0480

Dear Ms. Illona A. Jeffcoat-Sacco:

On behalf of Free State Synergies (FSS), I am pleased to respond to the Request for Proposal (Case No. PU-04-578) issued by the Staff of the North Dakota Public Service Commission (Commission), seeking regulatory expertise to address the reasonableness of Northern States Powers' (NSP) proposed rate increase.

FSS has substantial regulatory and expert witness experience and is well positioned to successfully complete this project on behalf of the Commission Staff Both David Dittemore (Project Manager for this engagement) and James Proctor have addressed revenue requirement issues and testified as expert witnesses on numerous occasions

Resumes and references for Mr. Dittemore and Mr Proctor are contained within this proposal As you will note, Mr. Dittemore and Mr. Proctor have approximately fifteen and twenty years of regulatory experience, respectively. Each has served as Director of Utilities and Chief Auditor for a state regulatory commission.

The task and responsibilities of the FSS team members are as follows

David Dittemore – Mr. Dittemore will serve as Project Manager for this engagement. He will analyze and submit expert witness testimony in the areas of revenue requirement, rate design and capital structure.

James Proctor - Mr Proctor will analyze and submit expert witness testimony in the area of the cost of equity.

FSS has submitted a proposed work plan for this engagement and has included it within this proposal. FSS states that neither Mr. Proctor nor Mr. Dittemore has any conflicts which would disqualify them from participation in this proceeding and will promptly sign any required statement confirming this fact. Further, FSS is in compliance with the Americans with Disabilities Act of 1991.

A Cost Proposal is also included within this response. The proposal of FSS encompasses the entire scope of work requested by the Commission. If the Commission desires only a portion of the work scope offered in this proposal, FSS is agreeable to entering into negotiations for individual components of the proposal Also, if FSS has misjudged the work scope for this project envisioned by NDPSC Staff, the final bid price may be negotiated The FSS bid encompasses the entire work scope set forth within the RFP. If you have any questions concerning this Response, please do not hesitate to contact me at 785-550-4774.

Sincerely,

James M. Proctor

James M. Proctor
President
Free State Synergies

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Cost Proposal Summary	Attached

Background

FSS and Associates will conduct a comprehensive review of the revenue requirements of NSP Mr David Dittemore will head up the revenue requirement analysis and rate design review and will be the primary contact for these portions of the project. Mr Dittemore has extensive experience in the field of public utility regulation, including significant work in the area of revenue requirements

Mr. James Proctor will conduct an investigation into the appropriate return on equity of NSP Mr Proctor has provided return on equity testimony in natural gas, electric and telecommunications rate proceedings and has provided substantial testimony in complex financial areas, including cash flow analysis between regulated and non-regulated operations supporting the assignment of debt between a utility and its troubled non-regulated affiliates.

The resumes of Mr. Dittemore and Mr Proctor are attached to this proposal.
Xcel is a registered holding company subject to the provisions of the Public Utility Holding Company Act Xcel subsidiaries provide electric and gas service in eleven states Its Northern States Power –Minnesota division provides natural gas service within its Minnesota and North Dakota jurisdictions.

On November 2, 2004 Northern States Power (NSP) filed a request with the North Dakota Public Service Commission (Commission) to increase rates $741,000 on an interim basis to be effective January 1, 2005. Xcel seeks a permanent increase of $1,280,000 to be effective November 2, 2005, based upon a 2004 calendar year test period NSP, an operating subsidiary of Xcel Energy, provides service to approximately 37,000 North Dakota customers.

On November 18, 2004 the Commission issued a Request for Proposal (RFP) seeking assistance in the evaluation of Xcel's rate increase proposal. The RFP seeks assistance in evaluating the reasonableness of NSP's rate proposal The consultant shall, a) analyze the filing, b) prepare discovery, c) prepare monthly progress reports of discovery highlighting ongoing findings and recommendations, d) prepare and file written testimony, e) provide oral testimony, f) assist Commission Staff in preparing cross examination of witnesses and g) assist Commission Staff in preparing proposed findings of fact. The specific scope of work includes a comprehensive review of NSP's proposed rate base, cost of capital, regulated net income and rate design.

Pursuant to state legislation, utilities have the option to utilize one of three test periods, a) a historic test period which may either represent data from the most recent twelve month period or the latest calendar year data, b) a current test period which is any twelve month period ending no later than twelve months after the date the schedules are filed, or c) a future test period including twelve months data ending no later than twenty four months

after the date schedules are filed. There are varying reporting requirements associated with each of the three test periods.

NSP's last rate proceeding (Case No PU-400-00-521) resulted in $500,000 increase in non-gas base rates, exclusive of manufactured gas plant (MGP) costs. The settlement agreement approved by the Commission permitted the recovery of MGP costs through a purchased gas adjustment mechanism over an eight year period with no rate base recognition or application of carrying charges MGP amounts recovered through the purchased gas adjustment mechanism are to be trued up annually to ensure the collection of total MGP costs of $2.88 million are not over or under-recovered. Further, these costs are to be collected from both sales and transport customers.

The Settlement Agreement concluded that an 11.5% ROE was appropriate as it fell between the 12% return advocated by NSP and the 11.3% return recommended by Commission staff.

The Settlement Agreement adopted the $5.50 residential customer charge recommended by Staff. The Agreement supported the separation of the distribution charge from the cost of gas charge and elimination of the declining block commodity rates for residential and commercial customer classes. The base rate increase to the interruptible class is one-half that of the overall increase.

Current Filing

Revenue Requirement

NSP's North Dakota filing is based upon an allocation or assignment of costs from NSP Minnesota's financial records FSS will examine the allocation of common costs (assets and expenses) to the North Dakota jurisdiction including a review of the underlying allocation ratios.

The filing relies upon an average 2004 rate base in arriving at the requested permanent increase of $1 28 million. FSS will examine the proposed rate base to determine whether the average balances have been properly stated. FSS will also evaluate the balance sheet of NSP to determine whether all cost free capital items have been properly identified.

FSS will identify any major capital additions occurring during the test period to determine if corresponding operating income impacts have been properly identified. This would include such items as large customer additions arising from additional investment, operational synergies and efficiencies associated with capital investment and annualized depreciation expense impacts from test period plant additions to name a few.

FSS understands that NSP may file test period updates as actual test period financial data becomes available. FSS will investigate material fluctuations in rate base and operating income as time permits within the procedural schedule

The NSP proposed rate base includes $1 8 million of unamortized MGP costs This proposal contradicts the Commission's order in Case No PU-400-00-521. The order authorized recovery of these costs over an eight year period with no rate base recognition or application of carrying charges Rate base recognition of these costs should be carefully considered in light of the clear Commission decision on this issue in the prior NSP rate case.

In July 2004 NSP notified the Minnesota Public Utility Commission that it discovered customer-billing errors dating back to 1998. The billing errors apparently impacted NSP North Dakota operations, however it is unclear the extent such errors may impact the 2004 test period FSS will investigate whether the billing discrepancies impact test period operations and quantify any appropriate adjustments.

Rate Design and Tariff Proposals

The residential class would incur a $1.22 million increase under the NSP proposal, equating to a 4.6% increase in base rates NSP indicates that based upon a class cost of service study (CCOSS), where each customer class incurs its respective cost of service residential customers would experience an 11.3% rate increase. However, NSP notes that other goals were considered in developing its rate proposals, including the need to limit rate increases to moderate levels for any given customer class, thus the impact to residential customers was limited to the requested 4 6% increase. The proposed rate increase results in a weighted average rate increase of 1.8%.

NSP states that over half of the fixed costs of providing gas distribution services to residential customers are collected through volumetric charges. NSP further indicates that per customer usage has been declining in recent years and coupled with the dependence upon the collection of fixed costs through volumetric charges has resulted in the under-collection of fixed charges which has adversely affected the financial condition of NSP.

NSP indicates that it is proposing significantly higher customer charges for residential customers designed to assign a greater portion of the fixed cost of service to the monthly basic service charge. Secondly, NSP is requesting to partially 'decouple' the recovery of fixed costs from customer usage. In the alternative to the partial decoupling proposal, NSP proposes a residential basic service charge of $14/month[1].

The decoupling mechanism would result in a true-up factor designed to adjust customer payments for the residential class to those levels that would have been charged if weather had been normal. NSP cites declining usage per customer over the past eight years due to appliance and equipment efficiencies and general fuel conservation efforts.

Each month the actual residential sales would be subject to a weather normalization calculation to determine the weather-normalized sales per customer. The difference between the actual sales per customer, normalized for weather and the actual monthly use

[1] Compared with the existing $5 50/month charge

per customer is multiplied by the Residential Distribution charge per therm effective during that month and by the monthly test year customers The product will be the Monthly Distribution Margin Differential Each month the differential will be recorded to a distinct sub-account of Account 186. Each year on June 30th carrying charges will be applied to the balance in this account to yield the Annual Distribution Margin Differential Adjustment

In addition to the partial decoupling proposal, NSP is proposing a number of tariff changes to various items including, elimination of gas yard lighting service, altering the exiting main and service extension policy, updating the limited firm rate and increasing the charge for returned checks

Work Plan

Procedural Approach

a. Obtaining an understanding of Commission Ratemaking Methodologies – Ratemaking principles vary by state and gaining an understanding of prior precedents is essential. FSS has not had an opportunity to identify such North Dakota specific methodologies prior to responding to this RFP, however this is the first order of business upon starting the engagement. FSS will discuss prior North Dakota methodologies with the Commissions' technical and legal Staff
b. Conduct On-Site Audit of NSP books and records and informal interviews with utility management[2] – FSS recommends a one-week on-site review during the discovery phase of this case FSS has found that on-site audit work in conjunction with informal discussions with utility management yields information that is otherwise generally not obtained through written discovery. FSS recommends extensive written discovery in this proceeding, however it also believes that a hands' on approach in conjunction with written discovery will provide the foundation for the best possible engagement on behalf of the Commission. This portion of the proposal is optional and the cost proposal contains an estimate of the incremental travel costs associated with the on-site review. If this review is not deemed necessary, the incremental travel costs may be deducted from the bid proposal.

   In the course of its on-site review FSS intends to review NSP Commission minutes, NSP General Ledger and Trial Balance information for periods prior, during and subsequent to the test period(s), internal audit reports, external auditor work papers, and supporting accounting records and vouchers requested based upon General Ledger review.

   FSS will also conduct informal discussion with NSP management in a number of areas including;

[2] If Commission Staff does not believe an on-site review is necessary, a combination of conference calls and discovery will be used in lieu of on-site review of books and records

i. Discussion of the scope of NSP non-regulated operations and how joint costs are allocated between regulated/non-regulated operations
ii. Discussion of the methodologies used to allocate costs between North Dakota, Minnesota and FERC regulated jurisdictions, including the scope of such costs allocated.
iii. Determining the organizational structure of NSP and defining any organizational changes occurring in the recent past, which may impact test period(s) operations.
iv. Defining the periodic management reports prepared to monitor budgets and utility performance.
v. Defining recent management priorities and initiatives that may impact ongoing operations.
vi. Discussion underlying the nature of deferred debits and liabilities on the books of NSP. The justification for inclusion of each regulatory asset and liability in the NSP' cost of service will be discussed. FSS will discuss both the rationale for changes to account balances since the last NSP' rate proceeding as well as reviewing underlying documentation supporting accounting entries.
vii. Discussion of major capital expenditures subsequent to the last rate proceeding, including a review of the economic rationale for such expenditures. Capital budgets will be evaluated to determine sources and potential impact of future expenditures on revenues and Operating and Maintenance (O&M) costs.
viii. Discussion of NSP compensation structure, including the extent of compensation comprised by incentives. The goal of this discussion topic is to determine whether objectives embedded in executive compensation plans are consistent with the public interest.
ix. Discussion of Pension, Post Retirement Medical Costs and Other Post-Employment Benefits (OPEBs) – FSS will determine the level of cost changes for these items over the past several years and inquire what steps NSP has taken to control costs in these areas

c. Identification of Major Issues – FSS will prepare a potential issues list after completing its on-site review[3] and submit to the Commission Staff for its review and advice.
d. Once a formal revenue requirement filing has been submitted, FSS will issue comprehensive discovery to analyze and evaluate elements of the NSP' revenue requirement. All major items within the NSP revenue requirement

[3] If Commission staff does not believe a field audit is appropriate the status report would be provided after review of the initial round of discovery responses FSS will provide written status reports to the Commission as frequently as desired

will be analyzed for consistency with prior Commission precedent, to determine if major cost elements have been prudently incurred and whether test period(s) operations are consistent with normalized results. Impact from test period(s) cost impacts and management decisions will be evaluated to determine if they have been properly annualized within the revenue requirement FSS will seek input from the Commission Staff in conjunction with discovery.

e After discovery is analyzed, FSS will present its preliminary findings to the Commission Staff for review and consultation.

f. Subsequently, FSS will prepare draft testimony and supporting work papers to submit to Commission Staff for its review and consultation

g. Final expert witness testimony.

h FSS will work with Commission Staff in developing litigation strategy and if requested will offer support and consultation involving any cost of service negotiations. FSS will assist Commission Staff in the preparation of draft cross-examination.

i. FSS will provide expert witness testimony at the technical hearing for this case and will assist with post-hearing brief preparation.

Technical Approach

Traditional ratemaking adjustments to historic (book) financial data can be categorized as follows.

Normalization Adjustments – These adjustments are justified when an unusual or non-recurring event happens during the test period. For example, an abnormal rise in fuel costs may drive up the utility's uncollectible expense beyond historic levels Such increases may not be reflective of an ongoing level of expense and an adjustment to reflect a more 'normal' level of expected expense may be required

Annualization Adjustments – These adjustments are offered in order to recognize a full years' impact of a certain transaction. A common annualization adjustment is to reflect the 'annualized' level of payroll expense due to an increase in wage rates during the test period. The adjustment would recognize the wage increase as if it had occurred at the beginning of the test period, thus increasing costs for those months of the test period prior to the effective date of the wage increase.

Out of Period Adjustments – Synchronization of revenue requirement elements is important in deriving the overall revenue requirement Often utilities will support adjustments to reflect cost increases far outside the test period, while ignoring other corresponding components of the Income Statement (such as revenue growth). SRS believes that synchronizing or matching revenue requirement components is essential in order to compute a just and reasonable revenue requirement. Any recognition of post test period cost changes should meet the 'known and measurable' standard and should be verifiable by the audit Staff. Recognition of increased costs (new plant for

example), while ignoring the benefits of the investment (lower maintenance costs), can produce an asymmetrical result, harming consumers.

Out of period adjustments are also supported when a certain transaction is recorded in the test period, but actually relates to a period outside the test period This adjustment is most often appropriate if an applicant uses a test period that differs from its fiscal period

The adjustment categories outlined above will be modified to incorporate any portion of the test period that is supported by forecasted data.

Given the importance of the decoupling mechanism and the significance of the weather normalization within the mechanisms computation, the Commission may determine that a detailed weather normalization analysis is appropriate. Mr Proctor has extensive experience in weather normalization adjustments FSS is presenting a weather normalization option for the Commission's consideration.

Specific Areas of Review would include, but not be limited to the following;

Revenue

- Evaluate operating revenues in light of trends in customer numbers by class.
- Identification of large industrial customers, both in terms of customer numbers and usage in order to evaluate whether test period revenues for this class is properly stated.
- Comparison of any forecasted revenue incorporated into the test period with actual operating results.
- Identification of jurisdictional portion of revenue misstated as a result of the billing errors noted above.
- (Optional) Evaluate impact of abnormal weather on North Dakota jurisdictional operating results (See Cost Proposal for the bid cost associated with this aspect of the proposal).
- Consider whether transmission revenues are properly identified for purposes of jurisdictional allocation methods

Rate Base

- Determine whether the average rate base elements were determined in a consistent manner.
- Evaluate major capital additions for potential corresponding impacts on Operating and Maintenance costs to ensure proper matching of revenue requirement elements.
- Investigate the reasons for any large fluctuations in test period account balances compared with balances in historic periods.
- Identify whether all appropriate rate base elements have been properly identified

- Identify material items of rate base, which are allocated/assigned to NSP – North Dakota jurisdiction and review whether such allocations are appropriate.

Expenses

- Investigate large fluctuations in test period account balances compared with historic periods.
- Identify test period costs associated with incentive compensation and determine whether the underlying payments should be included as test period costs.
- Compare test period payroll distribution between capital and expense and compare to historic levels.
- Evaluate the reasonableness of any forecasted expenses within the test period.
- Examine uncollectible expense within the test period to compare with historic averages.
- Define and quantify the scope of cost allocations from NSP total company costs (including rate base) to the North Dakota jurisdiction

Cost of Service/Rate Design

- FSS will evaluate rate design and cost allocation methodologies between classes for consistency with historic practices.
- FSS will offer alternative rate design options for Staff's consideration
- Cost allocation methods will be evaluated for reasonableness and underlying data will be tested for accuracy.
- FSS will analyze the decoupling mechanism to ensure NSP ratepayers are properly protected. FSS will consult with Staff in determining whether the decoupling mechanism is in the public interest. If the weather normalization option is selected, the results of the analysis may be incorporated into the decoupling calculation if such a mechanism is deemed appropriate.

Cost Proposal

As mentioned earlier, FSS is presenting the task of performing a weather normalization analysis and a one-week field audit as separate bid components. The not to exceed bid costs are summarized in the table below;

Description	Cost	On-site Audit	Weather Normalization
Option 1	$72,500	No	No
Option 2	$73,950	Yes	No
Option 3	$95,000	No	Yes
Option 4	$96,450	Yes	Yes

The bid proposal is further outlined on the FSS Cost Proposal attached at the end of this proposal.

The bid proposal estimates airfare at $600/trip and hotel rates of $75 - $100/ night for Bismark and Minneapolis respectively. Rental car rates are estimated at $50/day and per-diem is assumed at $30/day. FSS will abide by any standard reimbursement rates required by the state of North Dakota. Actual airfare will be billed if lower than that contained in this estimate. FSS would travel by auto to Bismark if convenient flights were not available.

FSS is willing to negotiate the cost of the project if only portions of the identified work products are desired by the Commission

Resume of James M. Proctor

Section I: General Qualifications

Mr Proctor has twenty years experience in regulating public utility companies for two state utility commissions and as a regulatory consultant primarily to state regulatory agencies As Director of the Public Utility Division of the Oklahoma Corporation Commission ("OCC"), as Chief of Accounting and Financial Analysis for the Kansas Corporation Commission ("KCC") and as a consultant to other state utility commissions, Mr. Proctor has been instrumental in formulating regulatory policy. While Director of the OCC Staff he directed staff's development and presentation of technical and policy recommendations before the OCC in the regulation of natural gas, electric and telecommunication utilities. As Chief of Accounting and Financial Analysis for the KCC, he managed the preparation of testimony and communication before the commission related to regulatory matters involving accounting, financial analysis and quantitative analysis. As Director, Regulatory Policy and Analysis of EnerTran Technology Company, Mr. Proctor was responsible for developing strategic regulatory policy and assisting EnerTran's principles in various aspects of the development of non-utility power generation projects. Most recently, Mr. Proctor has been providing consulting services to primarily regulatory agencies as a regulatory consultant As a consultant, he provides financial, accounting and policy consulting services regarding the regulation of electric, gas and telecommunications utilities. This consulting experience includes several assignments involving mergers and acquisitions of utilities, generally, and more specifically regarding identifying and quantifying merger synergies and evaluating acquisition premiums

Mr. Proctor has substantial experience over his career in the regulation of telecommunication utilities. This experience includes rate making, alternative forms of regulation, estimating the market value of telecommunications assets, developing rules for the implementation of local telephone competition and the unbundling of costs and rates.

Section II: Education

BBA Washburn University of Topeka, Kansas
Majors: Accounting and Mathematics, 1978

MBA University of Kansas
Majors: Corporate Finance and Operations Research, 1984

Section III: Work Experience

COMMISSION EXPERIENCE 1984-1993

Kansas Corporation Commission, 1984 -1990 Served as an expert staff witness before the Kansas Corporation Commission in numerous proceedings concerning financial and accounting and regulatory policy issues for electric, natural gas and telecommunication utilities Some of those cases are provided below.

Kansas City Power and Light Company, 1985 (Kansas) Testimony concerning adjustments to rate base and operating income statement, and evaluation of company's economic forecasting models.

Peoples Natural Gas Company, 1986 (Kansas). Testimony concerning the determination of hypothetical capital structure.

Union Gas Systems, Inc., 1987 (Kansas) Testimony concerning adjustments to operating income statement and estimation of return on equity

Kansas Power and Light Company, 1988 (Kansas) Testimony concerning a cash working capital lead-lag study and weather normalization

Kansas City Power and Light Company, 1988 (Kansas) Testimony concerning policy matters including: adjustments to rate base and income statement, recoverability of cost deferrals on excess investment in Wolf Creek Nuclear Plant, and, SFAS No 71 issues related to phase-in of plant costs

Kansas Gas and Electric Company, 1989 (Kansas) Testimony concerning the impact on ratepayers and shareholders from orders issued relative to the commercial operation of Wolf Creek Nuclear Plant including the present value of rate increase to customers; present value impact to shareholder equity from orders; and, comparison of market returns for company equity and utility industry during commercial operation of Wolf Creek.

Kansas Gas and Electric Company, 1989 (Kansas) Testimony concerning a cash working capital lead-lag study, weather normalization and capital structure.

Kansas Gas and Electric Company, 1989 (Kansas) Testimony for quantifying excessive fuel costs during unscheduled outages at Wolf Creek

Oklahoma Corporation Commission, 1990 -1993 Served as an expert staff witness before the Oklahoma Corporation Commission in numerous proceedings

concerning financial and accounting and regulatory policy issues for electric, natural gas and telecommunication utilities. Some of those cases are provided below.

Southwestern Bell Telephone Company, 1991 (Oklahoma) Testimony concerning rate reduction, rate refunds, network modernization investments and policy.

Oklahoma Gas and Electric Company, 1991 (Oklahoma) Testimony concerning return on equity.

Southwestern Bell Telephone Company, 1991 (Oklahoma) Testimony concerning return on equity.

Arkansas Louisiana Gas Company, 1992 (Oklahoma) Testimony concerning interim rate relief regarding revenue requirements, return on equity and policy

Oklahoma Gas and Electric Company, 1992 (Oklahoma). Testimony concerning policy matters including the following: motivation for show-cause investigation into rates; allocation of Cogeneration Capacity Related Costs, treatment of costs for acquisition premium related to Enogex pipeline; financial integrity and quality of service; retroactive ratemaking and interim rates; and, impact of rate decrease on market value of common stock.

Oklahoma Natural Gas Company, 1992 (Oklahoma) Testimony concerning interim rate relief regarding revenue requirements, return on equity and policy.

CONSULTING EXPERIENCE 1993 – Current

Cincinnati Bell Telephone Company, 1993 (Ohio). Served as project manager and provided testimony for a review of a proposed alternative regulatory plan on behalf of the City of Cincinnati.

Arizona Property Taxation Laws, Valuation of Telecommunications Property, 1993 (Arizona) Performed financial analysis for the Arizona Commission of Revenue (ADOR) to review the current definitions of telecommunications companies in Arizona, and issues related to the valuation of telecommunications properties based upon such definitions

US West Telephone Company, 1993 (Minnesota). Managed a staff of consultants in the review of the financial impact of alternative forms of regulation on the rates and earnings for a three period for the Minnesota PUC (1991-1993)

Cincinnati Bell Telephone Company, 1994 (Ohio). Served as project manager and filed testimony at the Ohio Commission regarding the review of alternative forms of regulation on behalf of the City of Cincinnati.

Citizens Utilities, 1994 (Arizona) Managed the review and preparation of a report regarding the financial valuation of utility investment in telecommunication assets on behalf of the Arizona Commission of Revenue.

EnerTran Technology Company, 1994 (Illinois). Managed the development of regulatory strategy at the Illinois Commerce Commission and Federal Energy Regulatory Commission for implementation of an independent power project for Corn Products Corporation.

Ener Tran Technology Company, 1995 (Illinois). Managed the development of regulatory strategy at the Illinois Commerce Commission and Federal Energy Regulatory Commission for implementation of an independent power project for Mobil Oil Corporation.

Southwestern Bell Corporation, 1995 (Oklahoma). Advised the Oklahoma Corporation Commission regarding the resolution and settlement of a rate case involving Southwestern Bell Telephone Company. Settlement involved customer refunds of $175 million and rate reductions of $90 million.

Local Telephone Competition, 1996 (Oklahoma). Prepared recommendations for the Oklahoma Corporation Commission concerning rules for the implementation of local telephone competition.

Kansas Gas and Electric Company, 1996 (Kansas). Audited electric rate case application and filed revenue requirement testimony at the Kansas Corporation Commission on behalf of Commission Staff.

Kansas Power and Light Company, 1996 (Kansas). Audited electric rate case application and filed revenue requirement testimony at the Kansas Corporation Commission on behalf of Commission Staff

Oklahoma Natural Gas Company, 1997 (Oklahoma). Audited gas contracts for prudence and prepared a series of reports for the Oklahoma Corporation Commission concerning findings.

Kansas City Power and Light Company, 1997 (Kansas). Audited electric rate case application and filed revenue requirement testimony at the Kansas Corporation Commission on behalf of Commission Staff.

Merger of Western Resources and Kansas City Power and Light Company, 1997-1998 (Kansas). Managed the Commission Staff financial and accounting

review of a merger application before the Kansas Corporation Commission Issues involved all matters related to accounting and financial analysis of corporate restructuring and merger synergy analysis for regulated and unregulated operations.

Local Natural Gas Distribution and Transportation Competition, 1998 (Oklahoma). Prepared recommendations for the Oklahoma Corporation Commission concerning rules for the implementation of local competition for natural gas.

Amended Merger of Western Resources and Kansas City Power and Light Company, 1998-1999 (Kansas). Managed the Commission Staff financial and accounting review of a merger application before the Kansas Corporation Commission and filed testimony concerning recommendations Issues involved all matters related to accounting and financial analysis of corporate restructuring and merger synergy analysis for regulated and unregulated operations.

Merger Agreement of Utilicorp United, Inc. and Empire District Electric Company 1999-2000 (Missouri) Consulting to Utilicorp United, Inc. to advise them on identifying and quantifying merger synergies; and to advise them on state and federal regulatory policy issues related to electric utility mergers, generally

Merger Agreement of Utilicorp United, Inc. and Saint Joseph Light and Power Company, 1999-2000 (Missouri) Consulting to Utilicorp United, Inc to advise company on identifying and quantifying merger synergies and other financial matters, and to advise them on state and federal regulatory policy issues related to electric utility mergers, generally.

Merger Proposal of Southern Union Gas Company for Southwest Gas Company 1999-2000 (Texas, Arizona, California and Nevada) Consulted to Southern Union Gas Company on state and federal regulatory policy issues related to gas utility mergers, generally.

Aquila Energy Corporation, 2000 Provided consulting services to Aquila Energy regarding utility regulation, generally, and specifically with regard to competitive gas businesses. Also, advised company regarding acquisitions of electric generation facilities.

Kansas Power & Light Company, 2000-2001 (Kansas) Audited electric rate case application and filed revenue requirement testimony at the Kansas Corporation Commission on behalf of Commission Staff.

Kansas Gas & Electric Company, 2000-2001 (Kansas) Audited electric rate case application and filed revenue requirement testimony at the Kansas Corporation Commission on behalf of Commission Staff.

Merger Agreement of Western Resources, Inc. and Public Service of New Mexico, 2001 (Kansas) Includes financial and accounting review of merger application. Issues involved include matters related to accounting and financial analysis of corporate restructuring and merger synergy analysis for regulated and unregulated operations.

Oklahoma Natural Gas Company, 2001-2002 (Oklahoma) Consulted to consumer group seeking relief from improper and excessive gas contract costs due to gas contract entered into above market prices for natural gas. Consumer group received refunds and other benefits of $48 million

Westar Energy, Inc., 2001-2004 (Kansas) Provided comprehensive testimony over a series of regulatory proceedings regarding diversified corporate structure and affiliate issues. Largely, the KCC relied on my testimony of financial analysis of Westar's diversified corporate structure to prepare its findings and conclusions in its review. I conducted financial analyses including studies of Westar and its non-utility affiliates' cash flow, to determine debt and assets properly attributable to utility and non-utility businesses.

Utilicorp, Inc / Aquila, Inc., 2001-2004 (Kansas) Provide advisory services to the Kansas Corporation Commission concerning the corporate structure and reorganization of Utilicorp Inc. and Aquila, Inc. Included financial analysis and affiliate/utility issues regarding non-utility subsidies and inter-affiliate allocations and transactions.

Kansas Gas Service Company, 2003 (Kansas) Audit and provide testimony on retail rate case issues.

Haviland Telephone Company, 2003 (Kansas) Audit and provide testimony on retail rate case issues.

Advisor on General Commission Caseload, 2001-ongoing (Kansas) Provide on-going consulting services to the Kansas Corporation Commission Advisory Council regarding financial, accounting and regulatory policy matters related to commission proceedings

Section IV: Work History

1984-1987 **Kansas Corporation Commission**
Senior Auditor and Financial Analyst, Responsibilities involved supervising audits of utilities, preparing return on equity analysis and provision of written and oral testimony in regulatory proceedings.

1987-1990 **Kansas Corporation Commission**

Chief of Accounting and Financial Analysis, Responsibilities involved hiring, training and supervising accounting and finance staff Also, prepared expert testimony regarding complex accounting, financial and policy matters before the Commission.

1990-1993 **Oklahoma Corporation Commission**
Director of the Public Utility Division, Responsibilities involved administering division operations, developing regulatory policy and testifying before the Commission and legislature regarding utility regulation.

1993-1994 **Overland Consulting, Inc.**
Director of Financial Analysis, Primary responsibilities included being the project manager for consulting engagements involving telecommunications utilities and directing the financial analysis used in the firm's consulting projects

1994-1995: **EnerTran Technology Company**
Director, Regulatory Policy and Analysis, Responsible for developing and directing regulatory strategy and financial analysis relating to competition in the generation and transmission of electricity Also, responsible for developing initiatives to implement regulatory policy change at state commissions

1995-Present: **Regulatory Consultant** Provides financial, accounting and policy consulting services regarding the regulation of electric, gas and telecommunications utilities.

Section V: References

Mr Scott Hempling, Attorney
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Areas of Expertise

- Analysis of Utility Revenue Requirement Proposals
- Analysis of Utility Mergers and Acquisitions
- Expert Witness Testimony
- Regulatory Accounting and Finance Issues

Qualifications

My tenure with the KCC included holding the positions of Director of Utilities as well as Chief Auditor In these positions, I directed the efforts of other regulators and gained a great deal of experience in conducting investigations, issuing discovery, conducting interviews designed to elicit information, identifying relevant regulatory issues, preparing testimony and defending the testimony in often contentious regulatory proceedings. I have experience as an expert witness, testifying an estimated 15 times on a number of topics, including revenue requirements, finance issues, regulatory accounting proposals, and general regulatory policy issues to name a few. I also have experience evaluating regulatory merger applications and developing associated policy recommendations My regulatory experience encompasses the Electric, Natural Gas and Telecommunication industries

Experience

Strategic Regulatory Solutions; 3/03 – Current

Provide written testimony on behalf of clients on a variety of regulatory issues. Perform prudence reviews on selected relevant issues as identified from review of utility operations. Conduct comprehensive revenue requirement analysis of utilities seeking rate increases Analyze cost allocations and other affiliate transactions for reasonableness and consistency with established costing principles

The Williams Companies; 2000 – 3/03

Manager Regulatory Affairs; Monitored and researched a variety of state and federal electric regulatory issues Participated in due diligence efforts in targeting investor owned utilities for full requirement power contracts. Researched key state and federal rules to identify potential advantages/disadvantages of entering a given market. Worked with Business Development group on a number of focused projects to identify potential acquisition targets. Internal customers served included Legal, Business Development, Origination, Structure and Governmental Affairs

MCI WorldCom, 1999 - 2000

Manager, Wholesale Billing Resolution; Managed a group of professionals responsible for resolving Wholesale Billing Disputes greater than $50K. During my tenure, completed disputes increased by over 100%, rising to $150M per year. Interfaced with executive management in resolving disputes as well as communicating quarterly results through verbal presentation. Participated significantly in employee recruiting activity on behalf of Revenue Services.

Kansas Corporation Commission; 1984- 1995, 1996-1999 –

Utilities Division Director - 1997 - 1999; Responsible for managing employees with the goal of providing timely, quality recommendations to the Commission covering all aspects of natural gas, telecommunications and electric regulation, respond to legislative inquiries as requested; sponsor expert witness testimony before the Commission on selected key regulatory issues; provide testimony before the Kansas legislature on behalf of the KCC regarding proposed utility legislation; manage a budget in excess of $2 Million; recruit professional staff; monitor trends, current issues and new legislation in all three major industries; address personnel issues as necessary to ensure that the goals of the agency are being met; negotiate and reach agreement where possible with utility personnel on major issues pending before the Commission; consult with attorneys on a daily basis to ensure that Utilities Division objectives are being met.

Asst. Division Director - 1996 - 1997; Perform duties as assigned by Division Director.

Chief of Accounting 1990 - 1995; Responsible for the direct supervision of 9 employees within the accounting section; areas of responsibility included providing expert witness testimony on a variety of revenue requirement topics; hired and provided hands-on training for new employees; coordinated and managed consulting contracts on major staff projects such as merger requests and rate increase proposals;

Managing Regulatory Auditor, Senior Auditor, Regulatory Auditor 1984 - 1990; Performed audits and analysis as directed, provided expert witness testimony on numerous occasions before the KCC; trained and directed less experienced auditors on-site during regulatory reviews.

Missouri Gas Energy (a division of Southern Union) 1995 - 1996

Senior Rate Manager 1995- 1996; Responsible for assembling all necessary data for first ever rate case filing by MGE; responded or reviewed hundreds of company responses to Missouri regulatory requests; directed and trained two regulatory analysts on rate case issues; developed revenue requirement model used in rate case filing; interfaced with on site regulatory auditors and coordinated all verbal requests for information,

Amoco Production Company 1982 - 1984

Accountant Responsible for revenue reporting and royalty payments for natural gas liquids at several large processing plants

Education

- B.S.B.A. (Accounting) Central Missouri State University; 1982
- Passed CPA exam; 1984 (Oklahoma certificate # 7562)

Personal Experience of David Dittemore

Sample of Revenue Requirement Analysis

Council Grove Telephone Company (Docket No. 04-CGTT-679-RTS) – Performed a revenue requirement analysis of Council Grove Telephone Company for purposes of determining the level of necessary intrastate subsidy. Areas of adjustment included rate base and various income statement issues, including affiliated transactions.

CenturyTel Rate Case (Docket 03-041) – Provided expert witness testimony on behalf of the Arkansas Public Service Commission on corporate cost allocation ratios used to assign corporate costs to CenturyTel's Arkansas operations

Haviland Telephone Company (Docket No. 03-HVDT-664-RTS) - Performed a revenue requirement analysis of Haviland Telephone Company for purposes of determining the level of necessary intrastate subsidy. Areas of adjustment included rate base and various income statement issues. I also provided policy testimony on the issue of the applicant's proposed use of a hypothetical capital structure in the context of determining an appropriate level of income tax expense Other issues included corporate overhead allocations and affiliated transactions.

KGS Rate Case (Docket 03-KGSG-602-RTS) Performed a comprehensive analysis of affiliated transactions, including significant asset transfers resulting in prudence adjustments on behalf of the Staff of the Kansas Corporation Commission. This review also focused on corporate costs, and various other income statement issues. KGS is an operating division of OneOk.

Kansas Pipeline Partnership Rate Case As Chief Auditor, I was the lead witness in this highly controversial case involving an intrastate pipeline attempting to recover extended startup costs.

Peoples' Natural Gas Rate Case As Chief Auditor, I was the lead Staff witness supporting accounting and finance adjustment to the rate increase request of People's, a division of UtiliCorp. My analysis included a review of affiliated transactions.

Southwestern Bell Telephone As Chief Auditor, I supervised the work of Staff in its joint review (along with the FCC and other SBC State PUC Staffs), of SBC affiliate transactions.

Kansas Power and Light Gas Rate Case As Chief Auditor, I was the lead staff witness providing revenue requirement testimony. My analysis included an analysis of prudence of the company's offering discounts to retail customer load

Wholesale and Retail Open Access

While employed by The Williams Companies, I had occasion to provide due diligence on a number of investor owned utility companies, reporting on the regulatory environment in which they operated. I was responsible for identifying any roadblocks or opportunities for prospective structured wholesale power transactions.

In addition, I have and reported on a number of retail open access legislation and corresponding regulatory unbundling orders in various states of interest to The Williams Companies. Through this experience, I am very familiar with the variety of issues, which surround open access implementation

Cost Benefit Analysis

KG&E/KCPL Coal Settlement Litigation (2 Cases) As the Managing Auditor for the Kansas Corporation Commission, I performed a review of complex production cost models in order to determine the cost and benefits of KG&E buying out of long-term coal contracts The project involved evaluating sensitivity analysis using probability studies.

Merger of Western Resources, Inc. and Kansas City Power and Light Company, 1997-1998 (Kansas). As Director of Utilities, I led the Staff investigation into the proposed WRI and KCPL merger, believed to be the first hostile takeover attempt in the utility industry. I presented the KCC Staff recommendation (lead Staff witness) and participated in a settlement agreement, which resulted in a near unanimous settlement The transaction was not consummated as a result of Western Resources' deteriorating financial condition.

Merger of Kansas Power and Light and Kansas Gas and Electric (1991) As Chief Auditor, I was the lead Staff witness and withstood cross examination on a number of issues, including acquisition premium recovery, estimated synergies from the transaction and a host of other accounting and policy issues.

Merger of UtiliCorp United (now Aquila) and Centel Electric (1991) As Chief Auditor, I provided staff testimony in the application of UtiliCorp to acquire the assets of Centel Electric. The impact of my testimony resulted in a refund to Centel customers

References

Don Low
Director, Utilities Division
Kansas Corporation Commission
1500 S.W. Arrowhead
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d low@kcc state.ks us
785-271-3220

Susan B. Cunningham
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s cunningham@kcc.state.ks.us
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Tim Thuston
Director Regulatory Affairs
The Williams Companies
One Williams Center-Resource Center
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Tim.Thuston@williams.com
918-573-2966

Mr. Bill Dennis
Manager Telecommunications
Arkansas Public Service Commission
1000 Center Street
Little Rock, AR 72201
Bill_Dennis@psc.state.ar.us

Free State Synergies

Cost Proposal - Northern States Power Rate Case

Case No. 04-578

Item	Notes	James Proctor	David Dittemore	Total
Return on Equity Analysis and Testimony	1	$ 20,000		
Revenue Requirement and Rate Design - Analysis and Testimony	1		$ 50,000	
Travel Costs	2			
Travel Costs for Technical Hearing				
Estimated airfare Tulsa to Bismark			$ 600	
Estimated airfare Kansas City to Bismark		$ 600		
Hotel - five nights		$ 375	$ 375	
Per-Diem		$ 150	$ 150	
Rental Car		$ 250		
Total Costs Option 1		$ 21,375	$ 51,125	**$ 72,500**
Travel Cost for Field Audit				
Estimated airfare Tulsa to Minneapolis			$ 600	
Hotel - 4 nights			$ 500	
Per Diem			$ 150	
Rental Car			$ 200	
Total Costs Option 2		$ 21,375	$ 52,575	**$ 73,950**
Weather Normalization Analysis		$ 22,500		
Total Costs Option 3		$ 43,875	$ 51,125	**$ 95,000**
Weather Normalization and On-site Audit				
Total Costs Option 4		$ 43,875	$ 52,575	**$ 96,450**

Notes

1 All tasks referenced above include the preparation of pre-filed expert witness testimony and providing oral testimony as an expert witness

2 This estimate assumed per-diem reimbursement of $30/day FSS will abide by the North Dakota per diem policies The rental car cost is estimated at $50/day

Option 1 = Base bid cost proposal, does not include on-site audit or weather normalization analysis
Option 2 = Option 1 plus one-week on-site field audit of NSP
Option 3 = Option 1 plus Weather Normalization Analysis
Option 4 = Option 1 plus on-site audit and Weather Normalization

Hudson River Energy Group
tailored solutions

December 2, 2004

Illona A. Jeffcoat- Sacco, Executive Secretary
North Dakota Public Service Commission
State Capital, 12th Floor
Bismark, North Dakota 58505-0480

RECEIVED
DEC - 3 2004
3/24
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Re. RFP For Case No PU-04-578

Dear Ms. Jeffocat-Sacco.

On behalf of the Hudson River Energy Group (HREG), I am pleased to submit to you this proposal regarding staff cost of service and revenue requirement assistance for formal Case PU-04-578.

Enclosed please find the required number of copies of HREG's response. We have reviewed the proposal and understand the objective of the contract to have a consultant that is experienced in utility ratemaking, revenue requirement calculations, cost of service studies and rate design HREG is has many years of experience in dealing with revenue requirements in different jurisdictions, for different types of utility and for different sizes (ranging from the smallest utilities with hundreds of customers to those that are among the largest in the country with millions of customers).

If you have any questions, please don't hesitate to call me as I am would be the primary contact for the contract I can be reached at the e-mail address or fax number shown on the letterhead or directly by telephone at (518) 436-1628. We look forward to hearing from you

Sincerely,

Frank W. Radigan
Principal

Enclosure

120 Washington Ave
Albany, NY 12210
Phone (518)436-1628
Fax (518)436-1630
E-mail fradigan@aol.com



RESPONSE TO NORTH DAKOTA PSC RFP FOR CASE NO. PU-04-578

REVIEW OF RATE REQUEST OF NORTHERN STATES POWER COMPANY GAS RATE INCREASE REQUEST

December 2, 2004

EXECUTIVE SUMMARY

The Hudson River Energy Group (HREG) proposes to work for the North Dakota Public Service Commission (the Commission) to review the gas rate request of Northern States Power (NSP). This response outlines the experience and background of HREG that serves as the main qualification sought under the request for proposals. We believe that HREG is highly qualified to serve Commission as we have almost twenty-three years of experience of utility regulation serving a broad array of customers and needs. We have performed numerous rate studies, stranded cost calculations, power supply analyses, cost-of-service studies, unbundling of services and negotiated long-term performance based rate plans in both cost-based regulated and deregulated environments

HREG brings the appropriate experience and expertise to accomplish the tasks set forth in the request for proposal We are a small firm that is focused on solutions and on maximizing deliverables to suit our clients' needs Frank W Radigan, Principal and founder of HREG, has twenty-three years' experience with regulatory accounting, ratemaking, depreciation, rate base calculation, rate design, cost of service studies, power supply planning, integrated resource planning, power production planning, economic analysis, appraisals and evaluations and modeling and has served as an expert witness in over forty proceedings.

EXPERIENCE AND PERSONNEL

HREG is an engineering and economic consulting firm specializing in the fields of rates, planning and economics for the electric, gas, steam, and water utility industries. HREG serves a wide variety of clients in dealing with the complexities of deregulation and restructuring, including stranded cost determination, OATT pricing, unbundling of rates, resource adequacy, and transmission planning policies and power supply. Our experience in these areas has brought us to testify before the Federal Energy Regulatory Commission and before the Utility Commission across the United States in over forty regulatory proceedings In addition to addressing restructuring and deregulation issues currently transforming the utility industry, HREG provides expert testimony, performs a variety of studies and services, and develops appropriate energy conservation measures

Backed by years of experience as a consumer advocate with a thorough understanding of the utility industry, HREG is well acquainted with the need for focused, diligent analysis and strategic approaches to problems This experience enables a small firm to provide a scope of deliverables far exceeding its size. Our broad experience over twenty-two years enables us to help clients adapt to meet current challenges while protecting consumers.

HREG provides a wide range of utility accounting and ratemaking consulting services to government agencies, state commissions and numerous other clients Projects and studies include Electric Restructuring, Wholesale Electricity Markets, ISOs and RTOs, Market Modeling and Price Forecasting, Performance-based Ratemaking, Expert Testimony, Energy

Procurement and Contract Negotiation and Policy, Stranded Costs and Generating Asset Valuation, and Cost-of-service Studies.

The motto of HREG is tailored solutions. This motto recognizes that no two utility cases are the same nor is there one answer for all clients For a municipal utility such as Hamilton, NY, the solution was to file a rate case so that the system could again regain positive cash flow. For the municipal utility Massena, NY, the right solution was to file an economic development rate so as to attract new customers to its system that has low cost rates For NUCOR steel, the solution was to intervene in numerous NYSEG rate cases so as to continue its flex rate contract that had benefited the customer and its community for many years For the State of Nevada, it was to analyze utilities filed depreciation studies to determine their reasonableness. For the State of Connecticut, it was analyzing water planning, weather normalization proposal and proposed depreciation rates. For the Village of Bath, it is developing pole attachment rate for cable TV. For the IBEW, it was advising on the financial health of a utility before labor negotiations began. The advice of HRGE was influential in each of these cases to the regulatory body. Hamilton received the rate increase it required. Massena's EDP rate is schedule to be approved at the PSC's December session. NUCOR an extension of its flex rate contract was obtained. The Nevada Commission hired HREG for a second assignment and adopted its recommendations in total In Connecticut, the utility's weather normalization and depreciation proposals were rejected in favor of HREG's recommendations. The Village of Bath is scheduled to files its new pole attachment rate next week. This list could be expanded to include each of HREG's clients, each with a different problem, ach with a different solution and each a story of success. HREG is proud that most of its work is from repeat customers and each of its clients can be contacted as a reference.

Examples of testimony provided in various cases that HREG has been engaged is available in electronic form by request

Frank W. Radigan

Frank Radigan is the Principal of the Hudson River Energy Group (HREG) utility consulting firm. Mr. Radigan's background includes 22 years' experience in the utility industry, with 15 years at the New York Public Service Commission where he was a senior engineer involved in rate making and policy making for electric, gas, and water utilities Since 1996, his work as a consultant has provided him the opportunity to work with a variety of clients, bringing his breadth of experience with the Commission to the challenges of today's utility industry.

Mr. Radigan received a Bachelor of Science degree in Chemical Engineering in 1981 from Clarkson University and a Certificate in Regulatory Economics from SUNY Albany in 1990.

Mr. Radigan has expertise in electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, retail access, generation planning and power supply agreements. He has served as an expert witness and provided testimony in over forty rate cases and various regulatory proceedings

Maggi Royle

Maggi Royle joined the Hudson River Energy Group in the Fall of 2003. She has extensive background in accounting and has proven invaluable in assisting in analyzing utility income statements, balance sheets and cash flow statements. Since joining the firm, Ms. Royle has taken over the financial analysis for the municipal and small utility clients of the firm.

Mr. Radigan and Mrs. Royle's resume can be found in Attachment A. A list of HREG's clients and references can be found in Attachment B.

STATEMENT OF TASK AND PRICE PROPOSAL

HREG has been involved in dozens of rate proceedings and based on that experience has recognized that the review of a rate case involves specific steps that must be done in a chronological order. The not to exceed budget follows the statement of task.

1. Review and evaluate all filings and supporting material, assist the Commission to analyze issues regarding rate case plan proposal and assist the Commission to identify alternatives to the utility's rate plan. Prepare memorandum on summary of rate case, critical issues, potential issues and rate impacts of issues.
    a. One week

2) Duplicate utility's rate case presentation to confirm revenue requirement calculations and develop template for alternative revenue requirement.
    a. One week for revenue requirement
    b. One week for cost of service study, revenue allocation and rate design calculations

3) Assist in conducting discovery of the parties to make a complete analysis of the issues, including aid in the preparation of written requests for information.
    a. One week

4) Assist in evaluating responses to discovery and other information provided by the parties in order to determine whether the case can be processed on the basis of the rate plan as filed or whether the Commission ought to raise additional sub-issues.
    a. Two days

5) Prepare monthly progress reports on conduct of case.
    a. One week (in total)

6) Prepare and file written testimony
   a. One week

7) Attend hearings and assist in cross examination of witnesses, written briefs, and findings of fact.
   a. One Week

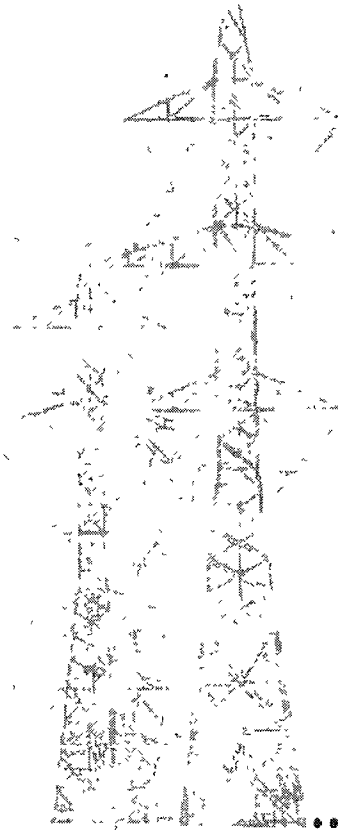
Task	Time (hours)	Cost
1	40	$6,000
2	80	$12,000
3	40	$6,000
4	16	$2,400
5	40	$6,000
6	40	$6,000
7	40	$6,000
Subtotal	296	$44,400
Travel	3 trips	$3,200
Total		$47,600

STATEMENT REDGARDING POTENTIAL CONFLICT OF INTERESTS

HREG has no conflicts of interests It and its employees have no relationships with any Company under jurisdiction of the Commission, or any subsidiaries or affiliates of such companies

Frank W. Radigan

Hudson River Energy Group



Hudson River Energy Group

...tailored solutions

ATTACHMENT A

Qualifications of

FRANK W. RADIGAN

Hudson River Energy Group
120 Washington Avenue
Albany, New York 12210
Telephone (518) 436-1628
E-mail fradigan@aol.com

EDUCATION

B.S , Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY --** Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements Perform depreciation studies, conservation studies and proposes feasible conservation programs

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness



testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies. Wholesale power system modeling with GE-MAPS.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Illion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity, determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD), forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs, participated in settlement negotiations for new rates 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served, performed valuation of the plant currently owned by Central Maine Power 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates, represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation, established customer education programs on restructuring, established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments, installed components on units in metropolitan NY region 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes. explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels 2004

Docket No ER03-563-030 -- Devon Power, LLC, *et al* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England.

Docket No 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG 2001

Docket No. EL00-62-005 – ISO New England Inc – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge June 2001

Docket No EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed Installed $0 17/kW/month Capability Deficiency Charge. January 2001

Docket No 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et al – New England Power Pool OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District. Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of

resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison. Gas Rates – Testified on reasonableness of utility's proposed depreciation rates 1994

Case 93-S-0997 – Consolidated Edison. Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility 1994

Case 94-E-0098 – Niagara Mohawk Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates 1994

Case 93-E-0807 – Consolidated Edison. Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison. Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric. Electric Rates – Review of utility's historic and forecast O&M expenditure levels, forecast and rate treatment of profits from wholesale power,

and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast, forecast and rate treatment of profits from sales of wholesale power, estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers 1984

PRESENTATIONS

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future. Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities

MEMBERSHIPS/ASSOCIATIONS

Member American Public Power Association, Northeast Public Power Association and New York State ISO

MAGGI ROYLE
169 Hasgate Drive
Delmar, NY 12054
518-439-6466

SUMMARY

An accountant with diversified business experience including financial statement and tax return preparation, software installation, and software training and support. Excellent organizational skills combined with good communication and problem-solving abilities.

EXPERIENCE

HUDSON RIVER ENERGY GROUP, Albany, NY – 9/03-present
Financial Analyst
Prepares rate and tariff filings for municipal electric and small water utilities Analyzes financial statements to determine revenue requirements Calculates rate based and prepares income statements, balance sheet and cash flow projections for clients.

DAFFNER & SCHMITZ, CPAs, Schenectady, NY – 11/02 to 9/03
Accountant
Prepare Federal and New York tax returns for individuals, corporations and partnerships. Preparation of financial statements for small businesses.

SOUTH, JOHNSON & CO , P A , Boise, ID – 11/98 to 7/02
Accountant
Primary responsibilities included client write-up, preparation of financial statements and individual tax returns. Assisted clients in establishing procedures to maximize efficiency of their accounting departments. Installed, set up and trained clients on QuickBooks. Prepared partnership and corporate tax returns Project management for partners and clients as needed.

MOUNTAIN SYSTEMS, INC , Boise, ID – 2/97 to 11/98
Senior Technician
Responsible for installation, training and follow-up support for MAS90 accounting software. Determined potential and existing clients' accounting requirements and document how MAS90 would solve their issues. Created and performed demonstrations to confirm that MAS90 provided solution to clients' needs.

PARTNERS PLUS, INC , Wilmington, DE - 8/94 to 12/96
Supervisor, Training and Client Support
Established accounting support department. Assisted clients in determining best accounting software for their needs and hardware required to run applicable software. Installed software and trained personnel on its use. Responsible for on-going support and general accounting help. Taught classes on Peachtree, QuickBooks, Windows, MS Word, MS Excel, and basic computer use

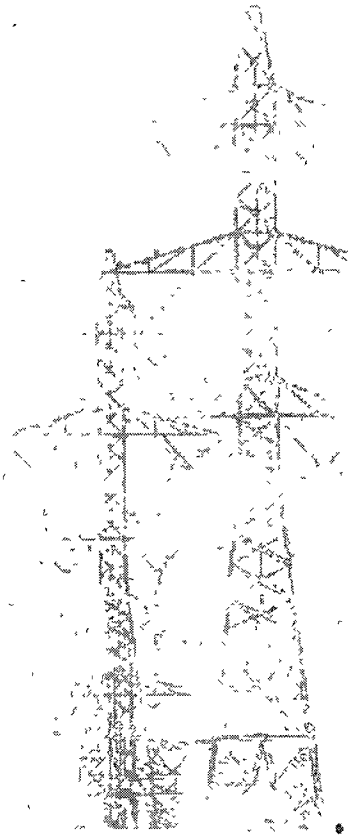
W C FENSTERMACHER, JR , CPA, Kennett Square, PA - 9/92 to 8/94
Staff Accountant
Prepared financial statements and payroll tax returns for clients and assisted them in accounting procedures Installed accounting software package and trained clients on its use Completed tax returns for corporations, partnerships, non-profit organizations and individuals

EDUCATION

Gear Up 1040 Individual Tax Seminar, 2000, 2001.
Practice Building with QuickBooks Seminar, 2001.
H&R Block Individual Tax Return Preparation Course, December 1993
The Job of the Controller Seminar, Boston College School of Management, 1986.
Accounting Certificate candidate, Northeastern University, 1986.
B.S., Marine Biology, cum laude, University of New England, 1980

REFERENCES

Available upon request



Hudson River Energy Group

...tailored solutions

ATTACHMENT B

CLIENT AND REFERENCES

CLIENTS

Municipal Utilities

City of Farmington, NM
Braintree Electric Light Department, Braintree, MA
Kennebunk Light and Power District, Kennebunk, ME
Massena Electric Department, Massena, NY
Middleborough Gas and Electric Department, Middelborough, MA
Norwood Municipal Light Department, Norwood, MA
Pascoag Electric Department, Pascoag, RI
Pascoag Water Department, Pascoag, RI
Reading Municipal Light Department, Reading, MA
Suffolk County Electrical Agency
Taunton Municipal Lighting Plant, Taunton, MA
Village of Arcade, NY
Village of Bath, NY
Village of Hamilton, NY
Village of Illion, NY
Village of Philadelphia, NY
Village of Richmondville, NY
Wellesley Municipal Light Plant, MA
Westchester County Public Utility Service Agency, NY

Investor Owned Utilities

Fillmore Gas Company, Inc.
Rowlands Hollow Water Works, Inc.

Government Agencies

Albany County, NY
Connecticut Department of Utility Control
Nevada Public Utilities Commission
New York State Attorney General, Albany, NY
Office of Consumer Counsel, CT
Town of Needham, MA
Vermont Public Service Board, Montpelier, VT

Hudson River Energy Group
tailored solutions

Law Firms

Brickfield, Burchette, Ritts & Stone, Washington, DC
Chadbourne & Parke, New York, NY
Couch White, Albany, NY
Duncan & Allen, Washington, D.C.
Kennedy & Christopher, P.C., Denver, CO
Kitch Drutchas Wagner Denardis & Valitutti, Detroit, MI
Morrison & Foerster, New York, NY
Moses & Singer, New York, NY
Read & Laniado, Albany, NY

Other Clients

Albany County Sewer District
Auburn Steel
Brooklyn Navy Yard Cogeneration Partners, LP
Henry Ford Health Systems, Detroit, MI
El Paso Merchant Energy
Independent Power Producers of New York
International Brotherhood of Electric Workers - IBEW
Multiple Intervenors of New York
NORCON Power Partners, New York, NY
Novo Windpower
Nucor Steel of Auburn, NY
New York Public Interest Research Group (NYPIRG)
Penobscot Indian Nation, Old Town, ME
The Energy Council of Rhode Island (TEC-RI)
US Generating Company, Bethesda, MD
York Research, New York, NY



REFERENCES

Mr Jay Brew, Esq.
Brickfield, Burchette, Ritts & Stone
1025 Thomas Jefferson
8th Floor, West Tower
Washington, DC 20007
Telephone. (202) 342-0800
Assignment: Numerous

Mr. Harvey Arnett, P E.
Chief, Downstate Rates
Office of Electricity and Environment
One Penn Plaza
New York, NY
Telephone: (212) 290-4385
Assignment: Numerous while at PSC

Mr. John Coyle, Esq.
Duncan & Allen
1575 Eye Street
Washington, DC 20005
Telephone (202) 289-8400
Assignment: Numerous Assignments

Mr. Paul Maguire
Public Utilities Commission of Nevada
1150 East William Street
Carson city, NV 89701
Telephone: (775) 687-6043
Assignment: Nevada Power and Southwest Gas

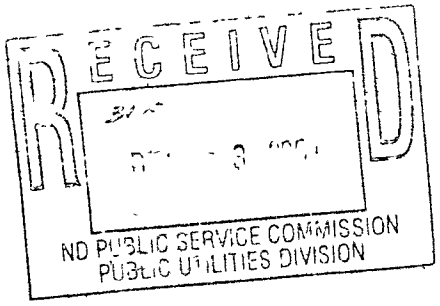
Mr. Mike Watza
Kitch Drutchas Wagner Denardis & Valitutti
One Woodward Ave, Tenth Floor
Detroit, MI 48226
Telephone (313) 965-7983
Assignment: Detroit Thermal on Behalf of Henry Ford Health Systems

Ms. Sharon Mann
Connecticut Department of Utility Control
10 Franklin Square
New Britain, CT 06051
Tel (860) 827-2675
Assignment Aquarion Water

A Proposal to Assist in an Investigation of the Northern States Power Company's Request for Rate Relief

Case No. PU-04-578

Prepared for
The North Dakota Public Service Commission
December 1, 2004



Gorham, Gold, Greenwich & Associates

Management Consultancy

Post Office Box 23626
Overland Park, KS 66283-0626

solve@ggga net

913.814 9820 vox
913 814 9083 fax

Gregory Loyd Mann, PhD
Raymond Adams B MBA Honorary Consul Republic of Kazakhstan
John Menzies PhD United States Ambassador
Kevin Prine, PhD
Aaron James Mann JD
Otval Fisher, MA CFP
Elias Li, MA

Michael Gallucci, JD
B Gunnar Johnson PhD
Tim Connolly, MS
Josh Li MBA
Ryan Charles Mann, MA MBA CMS
Travis Johnson, MS
Alexis Lara, JD

December 1, 2004

Ms. Illona A. Jeffcoat-Sacco
Executive Secretary
Public Service Commission of North Dakota
State Capitol – 12th Floor
Bismarck, North Dakota 58505-0480

Re: Request for Proposal, Case No. PU-04-578

Ms. Jeffcoat-Sacco:

Pursuant to your November 18, 2004 Request for Proposal please find enclosed an original and five additional bound copies of our firm's proposal to assist the North Dakota Public Service Commission in its investigation of Northern States Power Company's gas rate increase request. This proposal will remain on offer for 90 days from the date of this correspondence. Beyond that date any decision to honor the terms and conditions set forth in this proposal will be at the sole discretion of Gorham, Gold, Greenwich & Associates.

We appreciate the opportunity afforded us to submit this proposal and hope that it will be found compliant with your requirements. We believe the success of any engagement is measured by the ability of a consultant to correlate functional expertise, strategic perspective and analytical capability into an achievable outcome. We believe our proposal meets that test. Furthermore, we believe we offer the North Dakota Public Service Commission a unique set of credentials suitable to the Commission's needs in this proceeding. Specifically, we are –

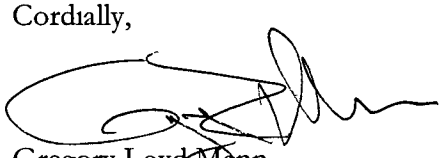
- capable of providing a broad range of functional support to the Commission;
- proven litigation support specialists;

- proficient in both procedural issues and subject matter at issue in this case;
- respected regulatory witnesses;
- qualified professionals in a broad range of disciplines; and
- effective communicators

In summary, we propose to provide a small team of highly-qualified professionals affording comprehensive support to the Commission's investigative effort. We fully recognize the challenges of addressing complex issues such as those presented in this case with the limited staff resources available to the Commission. Over the past fifteen years, we have served several regulatory agencies with similar constraints and worked diligently on their behalf to provide them with the best resources available. We make the same commitment in this proceeding.

If there are questions or additional information is needed please feel free to contact our office at your convenience, consult our webpage (www.ggga.net) or send an e-mail to me at gregm@ggga net

Cordially,



Gregory Loyd Mann
Managing Vice President

GLM/ejf
enclosure

A. Introduction

On November 2, 2004 Northern States Power Company d/b/a Excel Energy ("Xcel Energy" or "Company") submitted a request to the North Dakota Public Service Commission ("Commission") seeking rate relief to be made effective on January 5, 2005 In support of its request the Company argues that currently authorized rates create a revenue deficiency for its North Dakota natural gas utility operations

On November 18, 2004 the North Dakota Public Service Commission issued a Request for Proposal ("RFP) to assist in its investigation of the Company's request The Commission evidenced some concern in its RFP as to the Company's decision to incorporate a measure of rate rebalancing as part of its request. Given the relatively moderate revenue increase sought by the Company it is probably not unreasonable to assume that the general public's interest will be directed at the equity of the proposed rebalancing

B. Scope of Work

In the November 18, 2004 Request for Proposal the Commission expressed a need for assistance in "evaluating the overall reasonableness of NSP's rate increase request" [1] In the RFP, the Commission does not prescribe a specific standard that it expects to employ in this proceeding to judge reasonableness; therefore, we must assume that the scope of responsibility for this engagement will be to initially help the Commission identify an appropriate standard, establishing an investigative framework that will permit such a determination to be made and ensure acceptance of both by the Company's representatives.

We have also assumed in our proposal that the Commission will generally adhere to evidentiary rules it has employed previously in matters similar to that presented in this proceeding. We find no reference in the Request for Proposal to the effect that the Commission has adopted a specific set of rules for this proceeding. Accordingly, we believe that the scope of work envisioned for the consultant in this proceeding will not be to establish new rules of evidence or new procedural frameworks for use by the Commission but will generally conform to Uniform Administrative Procedure Rules (UAPR) and Generally Accepted Accounting Principles (GAAP).

The Commission has indicated its interest in a consultant (or consultants) to investigate, analyze and provide testimony regarding the Company's proposed rate base, cost of capital, regulated net income and rate design The consultant will serve as a technical resource to the Commission throughout the conduct of the proceeding. The Commission expressly tasks the consultant with a broad set of duties which we have interpreted to include –

[1] See **Request For Proposal** issued by the Public Service Commission State of North Dakota, November 18, 2004 at p 1.

- review and analyze all filings (testimony, interrogatory responses, briefs, motions, transcripts and arguments)
- prepare interrogatories and data requests on behalf of staff
- prepare and file written testimony
- stand cross-examination
- assist in the preparation of cross-examination
- assist staff in the preparation of proposed findings of fact

Third, we have assumed that the Commission's reference in the RFP to "written testimony" is limited to preparing rebuttal testimony. It is our experience in matters such as this that the Company bears the burden of proof in this matter, accordingly, staff will not be required to make a direct case of its own. We find no evidence in the RFP that the Commission has communicated to Northern States Power any intention to initiate a broader investigation than that prescribed by the Company's November 2, 2004 filing. If the Commission does envision staff presentation of a direct case in this matter Gorham, Gold, Greenwich & Associates reserves the right to revise this submission to make provision for the additional level of effort required by that activity.

Finally, we have assumed that any requirement the Commission may have for technical support in the event of a legal challenge to the decision in this proceeding will be covered by a separate, and subsequent, agreement between the Commission and Gorham, Gold, Greenwich & Associates

In the Request for Proposal, the Commission specified its interest in evaluating four principal areas of the Company's filing. Specifically, the consultant is asked to review and evaluate the company's current rate base, its cost-of-capital, its net income and its proposed rate design. The Commission's intent in examining each of these topics is to provide it the evidentiary foundation for its conclusions in this proceeding.

Each of the four topics will generate a level of investigative effort that corresponds to the complexity of the issue, the availability of support from the petitioner, the magnitude of any changes since the Commission last examined the matter and the significance of the matter to the eventual outcome. Below we outline what we believe to be the critical aspects of each topic that must be examined in this proceeding and the standards that must be satisfied.

- **Rate Base** – the size and composition of the company's rate base must be a reflection of genuine need, good judgment and responsible procurement policies

- **Cost-of-Capital** – an approved rate-of-return must continue to reflect current financial market conditions

- **Net Income** – the reported net income must be accurate and comport with prescribed accounting rules, reflect the best efforts of the company to achieve efficient operations and effective management

- **Rate Design** – the impact of any change to current rates must be fair to all subscribers, must be competitively neutral, must provide reasonable opportunity for the company to achieve its expressed goal and must be consistent with general industry practice.

In addition to these four areas of recognized importance, we believe some attention must be directed at the managerial – and financial -- relationship of Excel Energy to Northern States Power It has been our experience that the scope and scale of affiliate relationships, shared service agreements and contracted outsourcing can dramatically affect the cost structures – and net income levels -- of specialized business units such as Excel. As part of our proposal, we recommend issuance of a number of interrogatories that will seek to identify the extent to which the current business relationships between Excel Energy and its corporate affiliates may depress net income, artificially increase the size of the rate base and introduce an unwarranted level of risk to investment that must be recovered from the retail subscribers of Excel.

C. Approach and Methodology

The November 18, 2004 RFP does not expressly outline any procedural framework the Commission intends to employ in this proceeding but we are confident that it will be sufficient to accord the parties a) full and fair examination of their request and b) satisfy any legal test of due process that might be subsequently posed by any of the parties. The Commission has indicated that it expects written testimony by March 1, 2005 and hearings in mid-April, 2005 Assuming the Commission selects its consultant in a timely manner we find no reason to believe that the implicit schedule is insufficient to our needs or to those of the parties

It has been our experience that two "rounds" of interrogatories are sufficient to provide an adequate evidentiary base for preparation of rebuttal testimony and cross-examination. We are prepared to submit our initial set of interrogatories 10 business days after notification of the Commission's selection but no later than January 4, 2005. The second set of interrogatories will be issued within 5 business days of the Company's filed direct testimony with the Commission.

Additionally, we propose to submit written rebuttal testimony for legal preview by the Commission at a mutually acceptable date but no later than March 1, 2005.

Below we have summarized the schedule – and associated tasks – as best we can from the information provided by the Commission in the RFP. We envision this engagement to comprise a series of sequential tasks that follow a generally prescribed procedural schedule that accords each party adequate opportunity to present its case before any judgment is rendered.[2] We have designated with an asterisk (*) those events explicitly

[2] We assume, for purposes of this proceeding, that the Commission intends to grant the associated request for interim relief with a provision for refund if such a refund is

provided for in the RFP and endeavored to establish proposed dates for critical tasks and events that we believe are prescribed by the RFP for the consultant or implicit to the tasks and events prescribed

NSP Rate Filing Docketed with Commission	November 2, 2004*
Notice of Scope and Schedule Issued	December 15, 2004
1st Interrogatories Issued	January 4, 2005
1st Interrogatory Responses Due	January 20, 2005
Delineation of Relevant Issues	February 4, 2005
Direct Testimony Filed (Company)	TBD
Staff Testimony Filed	March 1, 2005*
2nd Interrogatories Issued	March 8, 2005
2nd Interrogatory Responses Due	March 22, 2005
Staff Cross-Examination Due	April 5, 2005
Hearings	April 15-25, 2005*
Initial Staff Findings of Fact	May 3, 2005
Briefs Due	May 10, 2005
Reply Briefs Due	May 24, 2005
Draft Decision Issued	June 8, 2005
Exceptions Due	June 15, 2005
Oral Arguments	June 22, 2005
Final Decision Issued	June 29, 2005

We fully recognize that the Commission may have established a procedural schedule beyond that suggested by the RFP and offer this to simply illustrate the scheduling framework that we employed in this proposal and the extent of the commitment that we believe may be required to support the Commission. We stand prepared, however, to accept any procedural schedule that the Commission may have already adopted for this proceeding.

It has been our experience that a close working relationship between the client and the consultant are essential to achieving the desired outcome in proceedings such as this. The Commission calls for a monthly progress report encompassing discovery, conclusions and recommendations from the consultant. We believe that written submissions should, whenever possible, be supplemented with discussion and debate. The Commission has not expressly indicated the need for such occasions but we propose to conduct a regularly scheduled monthly meeting with staff, legal advisors and interested members of the Commission (to the degree that *ex parte* rules permit) at a time convenient to the Commission The meeting will be preceded by a written submission no less than 5 working days prior to the meeting to provide sufficient opportunity for all interested parties to familiarize themselves with the topics for discussion

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subsequently determined to be necessary. Doing so provides the Commission the ability to thoroughly review the petitioner's request without immediate concern for time. It also provides the Commission plausible defense against any due process claims by the parties that might be raised if the schedule were significantly compressed or opportunities to present their case were abridged

After reviewing the Commission's RFP, we are of the opinion that the Commission's interest will be best satisfied by a small -- and decidedly-directed – team of subject matter experts in support of a senor executive from our firm We believe that this approach offers the Commission the means to translate disparate evidence developed in the course of the discovery process into a cohesive – and comprehensive – opinion sought by the Commission in the most effective manner. This approach also ensures a consistent representation of facts, findings and opinions in all matters related to the engagement Finally, it ensures the investigative effort focused at each aspect of this engagement is fully integrated into the final assessment of the Company's request and not subsumed by other issues of seemingly greater import.

It is our opinion – and it has been our experience -- that highly-focused teams of experienced professionals provide our clients with benefits not achievable with other sourcing strategies Specifically, our proposed approach –

- minimizes that portion of the engagement budget devoted to non-investigative activities such as project management,
- maximizes that portion of the engagement budget devoted to investigation and analysis activities,
- ensures consistency in the investigative methods, tools and techniques used in all areas of the engagement,
- permits more extensive cross-referencing and corroboration of evidence developed in each area of investigation;
- provides for better correlation of findings developed in each area of interest to the formulation of higher order conclusions,
- strengthens the Commission's ability to re-direct investigative efforts to specific areas of interest as the proceeding progresses;
- affords the Commission consistent findings, conclusions and recommendations in all areas of the matter;
- preserves the "perspective" needed to address the policy-level issues presented by the Company's proposed rate design;
- eliminates vulnerability of having testimony presented that conflicts with prior staff submissions; and
- affords the Commission greater access to – and use of – experienced consulting practitioners and witnesses.

For this proceeding we propose to employ Mr. Gregory Mann, PhD. as the principal witness in this proceeding. He will be supported in his effort by Mr. Ryan Charles Mann, MBA and Mr. Aaron James Mann, Esq. These individuals have worked together in support of a number of regulatory agencies in the past and provide a broad range of skills and experiences that will be of benefit to the Commission in this proceeding.

D. Firm Experience

Gorham, Gold, Greenwich & Associates is a professional corporation of experienced management consultants and business practitioners headquartered in Overland Park, Kansas and numbers clients in all parts of the world. The firm is a multi-disciplined management advisory firm formed in 1989 to assist members of the international regulatory community in achievement of their institutional goals and objectives The firm provides its clients advice, counsel and procedural tools integral to achieving success within present and proposed regulatory, legal, financial and technological frameworks. The firm specializes in developing responsive approaches to policy and management issues impacted by technological progress and new legislative frameworks. Gorham, Gold, Greenwich &Associates currently operates in North America, Asia, the Pacific Rim, the European Community, Latin America, the Confederation of Independent States (the former States of the Soviet Union) and the Caribbean basin. A general description of the firm's qualifications and experience can be found at www ggga net; accordingly we will not repeat information contained therein in this proposal but will refer interested parties to it for additional detail.

Gorham, Gold, Greenwich & Associates – as a matter of corporate policy – performs most of its consulting engagements on a proprietary basis. By specified terms of its contractual agreements, the firm maintains a confidential business relationship with each of its clients that transcends the specific timeframe of any active engagement These conditions preclude representatives of the firm from any public -- or private -- disclosure of such relationships unless those relationships are made public independently by the client or become a matter of public record in consequence or legal action or regulatory proceeding In the increasingly contentious marketplace for telecommunications and energy services, we respect the importance of client confidentiality and are committed to its preservation

With that proviso, we offer the following additional information to the North Dakota Public Service Commission for its consideration. The following engagements constitute a representative sample of work performed by Gorham, Gold, Greenwich & Associates in the past five years on behalf of domestic and foreign regulatory bodies and are a matter of public record. Although the engagements may differ in nature and subject from that under consideration by the Commission we believe they demonstrate the scope of our abilities and the depth of our experience. In those instances where our work is covered by confidentiality agreements, we sought to provide some perspective on the nature of that work in the individual *curriculum vitae* attached but without attribution in accord with the terms and conditions of those agreements.

1. Regulatory Proceedings

a. An Alternative Regulatory Framework for The Southern New England Telephone Company – provided policy advice to the DPUC Commissioners in matters related to a company-proposed price-cap regime. The engagement entailed developing a procedural framework for considering the proposal, establishing a statutory foundation for the Commission's actions, identifying all

probable scenarios that could be considered within the existent statutory boundaries as alternatives, identifying additional evidentiary needs beyond those presented by the interested parties, preparing staff for cross-examination, providing advice and counsel on procedural motions and rulings, developing assessment statements of evidence and assisting staff in the construction of a draft decision and order for the proceeding.

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, Connecticut 05610
Commissioner Jack Goldberg
860.827 2616

b. A Rate Investigation of The Innovative Telephone Company – conducted a comprehensive investigation of the financial condition on behalf of the Virgin Islands Public Service Commission to determine the reasonability of the extant rate-of-return authorized by the VIPSC in 1995. The investigation entailed a thorough examination of the corporation's financial management policies and practices as well as its compliance with the rules and regulations set forth by the VIPSC as a condition for authorizing its current rate-of-return. The engagement entailed identifying any changes in the company's approach to its business operations as a consequence of the VIPSC's actions in 1995 to determine any material effect on the quality of service provided to the end-user community. This engagement entailed filed testimony and extensive cross-examination before the PSC

Virgin Islands Public Services Commission
No 1 Fredericksburg Gade
St Thomas, US Virgin Islands
Attorney Frederick G. Watts, General Counsel
340.774.0673

c. A Request for In-Region Long Distance Authority for Qwest Communications Inc. – assisted the ACC staff with a comprehensive examination of Qwest's Operating Support Systems ("OSS"). The engagement entailed coordinating the investigation with a third-party testing firm on behalf of the ACC staff The purpose of this engagement was to provide the ACC a body of irrefutable evidence to

Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona
Matt Rowell, Chief Economist
602.542.0858
Maureen Scott, Attorney
602 542.6022

d. An Investigation of Affiliate Directory Publishing Agreements for Belgacom Communications – assisted a major European telephone company in preparing a legal defense of its service contract with a directory publishing affiliate The engagement entailed conducting a value analysis of the existent agreement and presenting it in testimony before the Directorate Generale IV as part of an anti-trust action. The premise of this engagement was to establish a framework of mutual benefit to both the Directory unit and the regulated utility emanating from the business relationship. Extensive efforts were made to demonstrate nature of the business relationship and the defensive value it provided to the regulated company.

European Union – Directorate Generale IV
Brussels, Belgium
Mr. Laurent DeSchrevel, Executive Director
32.303.83.32

e. An Arbitration Proceeding between The Innovative Telephone Company and Wireless World, NA. – served as the policy and technical advisor to the VIPSC in an arbitration case between a wireless provider and a rural telephone company. The engagement entailed development of a record for the proceeding that would substantiate any decision the Commission might subsequently make regarding removal of the rural telco exemptions to federal interconnection requirements prior to any determination of the application's merits. Extensive efforts were made to identify the need for additional rules and regulations to govern any approved wholesale provisioning agreement and ensure against discriminatory treatment of prospective competitors.

Virgin Islands Public Services Commission
St Thomas, US Virgin Islands
Attorney Fred Watts, General Counsel
340.774.0673

f. A Management Audit of Selected Retail Performance Measurements of the Southern New England Telephone Company – conducted a comprehensive examination of a self-reporting performance measurement system at the request of the DPUC. The examination entailed an exhaustive systems review, independent verification of business rules, extensive data interrogation and replication of the reported performance measurements to verify accuracy. Additional efforts were devoted to conducting sensitivity analysis and statistical modeling to identify the consequences of mandated changes to performance measurements and benchmarks.

Connecticut Department of Public Utility Control
New Britain, Connecticut 05610
Mr. Donald Downes
Chairman
860 827 2801

2. Testimony and Affidavits

Members of our firm have appeared in a number of legislative, regulatory and judicial forums in the course of their professional careers We offer the following as a representative sample of those appearances

Directorate Generale IV – European Union
Alabama Public Service Commission
Arizona Corporation Commission
California Public Utilities Commission
D.C Public Service Commission
Florida Public Service Commission
Hawaii Public Service Commission
Illinois Public Service Commission
Indiana Public Service Commission
New York State Public Service Commission
Texas Public Service Commission
United States Virgin Islands Public Service Commission
United States Senate Subcommittee on Nuclear Oversight
Virgin Islands Public Service Commission
Virginia Public Service Commission
Washington Public Service Commission
Wisconsin Public Service Commission

3. Public Utility Experience

Similarly, our team members have worked on behalf of a number of telecommunications and energy-services providers on matters of managerial compliance and operational performance. The list includes.

Alabama Gas Company
Alabama Power Company
AT&T Communications
Bell Atlantic Communications
British Telecom
Carolina Power & Light Company
Central Louisiana Electric & Gas Company
Consolidated Edison Company of New York
General Public Utilities Corporation
GTE Communications
Hong Kong Telecom
Jersey Central Power & Light Company
Montana Power Company
Omaha Public Power District
Qwest Communications
SBC Communications

Singapore Telecom/Temasek Holdings Corporation
Telecom Italia
Verizon/GTE Directories Corporation
Washington Water Power Company

The Request for Proposal asked that references be submitted for parties that have not previously contracted with the Commission. In addition to the specific consulting engagements discussed above we offer the additional individuals for consultation and consideration by the Commission. It is our opinion that these individuals can attest to our competency and capability in matters such as those presently before the Commission in this proceeding.

None of the parties have been apprised of their inclusion in this proposal and, if contacted, may be reticent discussing the specifics of any engagement performed on behalf of their firm or agency. By including them in this list Gorham, Gold, Greenwich & Associates makes no representation that any disclosure beyond that contained herein will be made by the referenced parties. Gorham, Gold, Greenwich & Associates can only attest to the fact that disclosures made for this purpose meet the contractual terms set forth previously in any agreements with these parties and represent its best efforts to comply with the Commission's request.

We offer the following individuals for consideration of our qualifications for this engagement:

Mr. Steven Banta
Vice President
Verizon Communications
600 Hidden Ridge Road
Irving, Texas 75038

Ms. Jan Beecher, Ph.D.
Director
Institute of Public Utilities
Michigan State University
240 Nisbet Building
Ann Arbor, Michigan 48823

Mr. David W. Bogan
Robinson & Cole LLP
Financial Centre
695 East Main Street
Stamford, CT 06904-2305

Mr John Betkoski
Commissioner
Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, Connecticut

Ms Ramona Carlow
Vice President – Regulatory Matters
The Southern New England Telephone Company
310 Orange Street -- 3rd flr
New Haven, Connecticut 06510

Ms. Kathleen A. Carrigan
Vice-President, General Counsel & Secretary
ISO New England Inc.
One Sullivan Road
Holyoke, Massachusetts 01040-2841

Mr Walter L. Challenger
Chairman Emeritus
Virgin Islands Public Services Commission
Post Office Box 861 Charlotte Amalie
St. Thomas, US Virgin Islands 00804

Mr Paul J Corey, Esq
Counsellor at Law
Brown Rudnick Berlack Israels LLP
City Place 1
Hartford, Connecticut 06103

Mr. Donald Downes, Esq.
Chairman
Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, Connecticut 06051

Ms. Heather F. Hunt, Esq.
Commissioner Emeritus
Maine Public Service Commission
w.h.Robert &h.f Hunt,LLC
Stamford, Connecticut
(203) 380-1477

Mr. Jack Goldberg
Vice-Chairman
Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, Connecticut 06051

Mr. Valencio Jackson
Chairman
Virgin Islands Public Service Commission
PO Box 40 Charlotte Amalie
St. Thomas, US Virgin Islands 00804

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Assistant to the Governor
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Mr. Howard Tarler
Director -- Wholesale Energy Markets
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Mr. Gregory Vogt, Esq.
Principal
Wiley, Rein & Fielding
1776 K Street, NW -- 11th Flr
Washington, DC 20006

E. Personnel

As we indicated in our discussion above, Mr. Gregory Mann, Ph D. will serve as the lead consultant and principal witness in this proceeding. Mr Mann is a trained economist and accomplished witness. He has appeared before state and federal regulatory agencies, Congressional committees and foreign judicial bodies. Mr. Mann has served as a public policy advisor for a number of international regulatory bodies over the past 20 years. He is a respected expert in matters of affiliate interests, organization design, corporate governance, mergers and acquisitions. Mr. Mann consults with a broad range of clients – regulatory agencies, owner/operators of utilities, investment banking firms and ratings agencies, corporate law firms – seeking expert advice and opinion on matters related to regulated utilities Mr. Mann's participation in this proposal affords the Commission the benefit of 30 years experience, knowledge and perspective working with all manner of regulated utilities in a widee range of issues.

Assisting Mr. Mann will be two professional members of our firm's staff – Mr. Ryan Mann and Mr Aaron Mann.

Mr. Ryan Mann, MA, MBA, CMS is a trained managerial finance specialist. Mr. Mann will play a critical role in evaluating the company's financial structure and strategy at the direction of the lead consultant. He will also be integral to efforts to assess the strategic consequences of the Company's proposed rate design and propose any modifications that might prove beneficial.

Mr. Aaron Mann, JD is trained corporate litigator. In addition to his litigation skills, Mr. Mann has extensive experience in the areas of administrative procedure and regulatory frameworks. At the direction of the lead consultant, Mr. Mann will be responsible for composing interrogatories, data requests and cross-examination, providing procedural advice and performing directed research as required by the lead consultant

The efforts of Messrs. Mann will be supplemented with additional specialized support by the firm's staff to ensure continuity and efficiency in our investigation. Specifically, we propose to use a Project Administrator (Ms. Heidi Bruce) who will be responsible for scheduling, invoicing, report preparation and other administrative tasks. Additionally, we propose to use a Technical Editor (Ms. Jeanne Fisher) to improve the organization and quality of the final testimony, a Technical Consultant (Mr. Joseph Garretson) to manage the electronic documentation filing system we expect to employ; a Litigation Support Specialist (Mr. Brian Epps) to serve as the document manager for the engagement. We believe that the addition of Mr. Garretson, Ms. Fisher, Ms. Bruce and Mr. Epps will guarantee the Commission the highest quality work product and administrative attention it seeks and it deserves.

It bears mention that no cost for the services of Ms. Fisher, Ms. Bruce, Mr. Garretson and Mr. Epps is reflected in the quoted price for this engagement We find the services rendered by these individuals to our efforts of such importance that we provide

them to our clients at no cost It is our hope that -- like us -- you recognize the benefits that these individuals provide in the proposed engagement

The resumes for each primary member of the team are appended at the end of this proposal. As indicated above we envision that only Mr. Gregory. Mann will serve as prospective witnesses in this engagement. Mr Ryan Mann and Mr. Aaron Mann will assist in the development of evidence and construction of Mr. Gregory Mann's testimony All three individuals will participate directly in analyzing the Company's submissions and developing interrogatories and cross-examination.

F. Potential Conflicts of Interest

Gorham, Gold, Greenwich & Associates LLC has no current business relationship with any of the parties designated in this engagement for examination by the North Dakota Public Service Commission Additionally, it has no past business relationship with any of the parties designated in this engagement for examination. This declaration extends to any past or present affiliates of the designated parties

Furthermore, by this declaration we attest to the North Dakota Public Service Commission that – to our knowledge -- we have no other current or past business relationship with any individual, institution, agency or professional firm that has been party to any proceeding involving the designated parties in this proceeding that requires disclosure. With those declarations made we are of an opinion that we have no potential conflict of interest – or anything that would present the appearance of a conflict of interest – to performing this engagement on behalf of the North Dakota Public Service Commission.

G. Cost and Price Analysis

Pursuant to the directions of the Commission in its Request For Proposal **Gorham, Gold, Greenwich & Associates LLC** has formulated a fixed cost estimate to perform the prescribed set of tasks set forth in the RFP and those set forth in the scope of work above.

We have estimated that the professional fees for this engagement will be $95,000. Expenses are projected to be $6,500. We are prepared to commit to the Commission that the cost for this engagement will not exceed $101,500 unless the scope of the engagement is substantially changed and/or the level of effort is appreciably increased from that suggested by the Commission's November 18 Request for Proposal. If either -- or both -- of these two conditions are encountered we reserve the right to seek reconsideration by the Commission. However, we believe our proposed fees and expenses are sufficient to meet the stated requirements set forth in the RFP and find no reason to believe that any such reconsideration will be needed or necessary.

We would call the attention of the Commission to the following facts that may not be readily apparent in the above referenced commitments. Specifically,

- all expenses are billed at cost with no administrative markup and summarized by expense category with each invoice submitted to the Commission
- total expenses are projected to be $6,500 and represent less than 7% of the proposed engagement cost.
- no cost for administrative assistance will be billed to the Commission
- the commitment of our firm's most experienced consultant to this engagement equates to 30% of his available time for a six-month period;
- no cost for editorial assistance will be billed to the Commission.

We generally offer our client a discount of 1.5% on fixed fee projects if they agree to "levelized" summary billing rather than detailed billing. In this instance, we would agree to a $100,000 fixed fee payable by the Commission in 5 monthly installments of $20,000 each commencing on the 1st day of the month following appointment as the Commission's consultant Given the fixed fee requirement specified by the RFP we believe this option may suit the interests of the Commission. Under such an agreement, our firm assumes all responsibility for managing all costs of the project including expenses for the duration of the engagement.

H. Time Estimates

We have reviewed the tasks set forth for completion by the Commission in its Request for Proposal with our staff and find them to be relevant topics and reasonable requests. We believe them to be consistent with the tasks we have seen in other engagements of similar scope and within our experience to address. Furthermore, we believe that the procedural framework set forth in this proposal is of sufficient rigor and reliability that it will generate the evidence necessary to address each of the subjects to the satisfaction of the Commission. Finally, we believe the professional staff we have proposed for this engagement possesses sufficient skill, intellect, and experience to reconstitute the disparate evidence identified in this investigation as definitive conclusions and properly advise the Commission to its probity and pertinence.

In summary, we have based our estimate on a) the proposed scope of work, b) our professional experience in similar matters and c) the specialized nature of the issues to be addressed in the engagement. It is our opinion that the proposed effort will demand at least 600 man-hours of effort expended by a team of three consultants over a five-month period. We believe that level of commitment is necessary to address all of the issues identified by the Commission in a manner that ensures accuracy, cohesiveness and fairness.

It bears note that specific provision has been made in the time estimate for fact verification exercises, progress reviews and staff briefings. We have found that these activities materially improve the probity of evidence developed in this type of investigation, substantially reduce points of disagreement between the parties and afford a unique opportunity for staff to acquire additional subject matter knowledge and investigatory skills in a relatively efficient manner. We are sufficiently confident in our overall projection of 600 man-hours although we may find it beneficial to adjust our attention within the budgeted commitment to certain areas of investigation as the engagement ensues.

The stated commitments assume the full cooperation of Excel Energy, its corporate parent and its affiliates; also, the availability of information sought by the consultants in the course of their examination It has been our experience in similar proceedings that some deviation will result from the work plan to reflect differences in the conditions encountered in the actual investigation – and some slight differences in the hours committed to each of the individual task areas may be necessary; however, the overall deviation is projected to be insignificant.

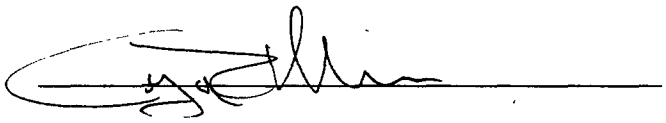
I. Period of Offer

This proposal remains on offer until such time as the North Dakota Public Service Commission selects a consultant for this proceeding or 90 days from issuance whichever comes first After that time, Gorham, Gold, Greenwich & Associates reserves the right to rescind, revise or restate any terms and conditions contained herein All terms and conditions set forth herein will be honored by Gorham, Gold, Greenwich & Associates if this proposal is accepted in writing by the North Dakota Public Service Commission within that period of time.

J. Willingness To Work

Gorham, Gold, Greenwich & Associates LLClooks forward to the opportunity to work with the North Dakota Public Service Commission and its staff project officer. We expect to include the Commission's representative in all aspects of the engagement – management interviews, planning sessions, analyzing interrogatory responses, fact verification – with the intent of ensuring the Commission is fully apprised of the progress of the investigation. Our experience has been that a high-level of involvement by the Commission's project officer is beneficial to both the consultant and the Commission

K. Signatures



Gregory Loyd Mann
Managing Vice President
Gorham, Gold, Greenwich & Associates LLC

Gregory Loyd Mann
Managing Vice President
Consulting Vitae

EDUCATION

BA	--	Graceland College
MA	--	University of Missouri
PhD	--	University of Missouri

AREAS OF SPECIALIZATION

Regulatory strategy, affiliate interests, organizational strategy and design, privatization planning, acquisition and merger analysis, infrastructure initiatives, strategic market planning

CONSULTING EXPERIENCE

- Directed a comprehensive examination of the regulatory strategy, business development and shared corporate responsibilities of a major telecommunications holding company. The purpose of the engagement was to improve the level of continuity existent between the regulatory strategy, the corporate planning and service delivery organizations of the company. The scope of the engagement encompassed questions of plan formulation, program communication and process compliance

- Directed development of a comprehensive framework for affiliate interest regulation for a major independent telecommunications services provider. The engagement entailed development of subsidiary acquisition/affiliation criteria, transactional approval procedures, evaluation techniques and regulatory compliance procedures

- Directed a technical services delineation study for a major telecommunications services provider The products of this engagement will provide the theoretical foundation for allocation of technology responsibilities between the regulated units, the service company, corporate staff, independent manufacturers and other corporate-funded research/development organizations.

- Directed development of an affiliate interest evaluation framework for establishing value in technical support services offered by Bell Communications Research to a major telecommunications services provider. Emphasis was placed on identifying the appropriateness of the affiliate relationship and demonstrating the financial and operational value of its continuance.

- Directed development of an affiliate service offering profile for a leading telecommunications services provider. The purpose of the engagement was to identify potential internal service relationships between corporate subsidiaries. The engagement entailed development of individual unit capability profiles, identification of regulatory and judicial precedents, delineation of affecting issues and implementation requirements. The products of this engagement were used to demonstrate to regulators the economic benefit associated with such business relationships.

- Directed development of an affiliate risk assessment position statement for a major investment banking firm engaged in telecommunications merger and acquisition activity. The purpose of the engagement was to establish a mechanism for evaluating incremental contribution potentially derived from current or proposed affiliate relationships

- Directed development of a contractual framework between a local exchange carrier and its affiliate directory publisher. The engagement required identification of appropriate financial terms and incentives for each party as well as establishing contribution levels and attendant conditions necessary to satisfy regulatory concerns.

- Directed development of a contractual framework for a major global telecommunications services provider for use by the individual regulated subsidiaries as the basis for negotiating with the directory publishing subsidiary unit of the parent corporation. The engagement focused on ensuring financial equity for each of the LEC units and conditional equity amongst all parties within the contract.

- Directed an operational audit of the affiliated interests of a major independent telecommunications service provider The purpose of this examination was to determine the presence and use of prudent management control systems that govern the network of affiliated relationships existent between the respective subsidiaries of the corporation.

- Directed development of affiliate interest internal audit procedures for a major telecommunications services provider at the request of the Internal Audit organization of the client. The purpose of such procedures is to provide internal auditors a set of general management principles to complement the general accounting practices necessary to effectively evaluate affiliate relationships between commonly-owned, but independently-managed subsidiary business units.

- Directed development of a state regulatory strategy for a multi-state utility holding company. The purpose of the strategy was to enlist support of the respective PSCs for the acquisition of another investor-owned electric utility. Support included developing consistent corporate representations for both state agencies, creating a strategic theme for use by all participants; preparing presentations and witnesses; providing both the strategies and tactics needed to achieve PSC concurrence with management's proposed actions

- Directed development of a state regulatory strategy for an electric utility seeking removal of PSC-imposed limits on non-utility investments. The engagement included developing a theoretical foundation for the request, the "sales" strategy to be employed with the PSC and the specific concessions that might be made to secure the necessary regulatory concurrence.

- Policy advisor to a state regulatory agency in matters related to a rate investigation of an incumbent local exchange carrier Responsibilities included serving as adjunct staff for the agency in the development of evidence and argument principally associated with the affiliate relationships between the regulated telephone company and its nonregulated counterparts.

- Directed a comprehensive examination of a proposed business diversification plan (ie. creation of a competitive access provider network from the client's core fiber optic network) of a major electric utility. The engagement emphasized proper definition of core telecommunications competencies, identifying competitive advantages and establishing a basis for differentiation from other CAPs.

- Directed a comprehensive review of telecommunications requirements supporting the nuclear operations of a major electric utility. The engagement focused on determining the level of compliance on the part of the client with NRC-mandated telecommunications requirements for voice, data and telemetry applications at their nuclear generating facilities.

- Directed a comprehensive evaluation of proposed changes to a customer-owned and maintained microwave network of a major electric utility The engagement sought to evaluate the economic and operational value of fiber-based networks over generational microwave improvements.

- Directed a comprehensive assessment of a telecommunications-based energy management program sponsored by a major electric utility. The engagement sought to improve the operational efficiency of telecommunications transmission networks by repackaging specific applications and priorities.

- Directed a focused examination of the customer services operations of a major electric utility. The engagement emphasized the productivity improvements presented by increasing the use of technology for customer routing, qualification and information response.

- Directed a focused examination of the customer services operation of a major electric utility. The engagement emphasized the operational flexibility (ie. decentralized customer services operations) afforded by extension of fiber-based telecommunications networks available to the company.

- Directed development of a telecommunications-based DSM product strategy on behalf of a major telecommunications/information technology manufacturer The engagement emphasized packaging and position product elements in support of the corporation's marketing strategy.

- Directed development of a market feasibility assessment and positioning strategy for a multi-state electric utility holding company. The engagement focused on developing regulatory, financial and competitive strategies for corporate expansion into the telecommunications market

- Directed a feasibility assessment for an electric utility considering financial participation in the interLATA telecommunications business. The engagement endeavored to identify the most appropriate role for the client as well as the relative risk reward associated with any participation.

- Directed development of point-of-use power systems strategy for support of LEC broadband infrastructure deployment. The engagement focused on defining opportunity, developing pricing, packaging and performance standards associated with the prospective electric utility business initiative.

- Directed development of a divestment strategy for the Internet Services Provider (ISP) business unit of an investor-owned electric utility. Emphasis was directed at determining the relative value of the business unit, identify prospective buyers and establish an orderly transition for customers.

- Policy advisor to a state regulatory agency in matters related to the review of an ILEC application for long-distance authority under terms and conditions set forth in 47 U.S.C § 271. Responsibilities include assisting the commission in developing a full and fair record of evidence that accurately reflects the level of compliance by the ILEC with the rules and regulations set forth by the Federal Communications Commission and the United States Congress.

- Policy advisor to a state regulatory agency in its review of a §271 application by an incumbent local exchange carrier. Emphasis in the engagement was directed at identifying impediments to completion of the engagement and the development of a comprehensive record for use with the Department of Justice and the Federal Communications Commission.

- Policy advisor to a Central European government agency in the conduct of an operational and managerial evaluation in advance of privatization of a state-owned telecommunications firm Emphasis was placed on determining the level of incremental investment necessary by any private sector investor to provide EU equivalent services.

- Policy advisor to an East European Post and Telecommunications agency in the development of an international partnership Emphasis was placed on defining the

most appropriate organizational structure for the joint venture and the working protocols for its representatives.

- Policy advisor to a state regulatory agency seeking to construct a multi-provider telecommunications market Emphasis was on providing policy assistance to the Commissioners in matters related to unbundling, pricing, affiliate matters, universal service funding and depreciation matters.

- Policy advisor to a state regulatory agency seeking to construct independent wholesale and retail service delivery systems for telecommunications services. Emphasis was on providing assistance in matters of organization design, codes of conduct, federal regulatory comportment and implementation strategy.

- Policy advisor to a state regulatory agency seeking to evaluate an application for statewide CATV operating authority by a certified telecommunications services provider. Efforts were directed at determining statutory conformance of the petitioner's application and the scope/scale of any unintended competitive advantage afforded by approval of the application.

- Policy advisor to a state regulatory agency in matters related to the examination and evaluation of an application by a CATV operator for authority to serve as a telecommunications services provider. Efforts were directed at determining statutory conformance of the petitioner's application and the scope/scale of any unintended competitive advantage afforded by approval of the application.

- Policy advisor to a European regulatory agency in a review of a proposed merger between two international telecommunications services providers. Emphasis was devoted to identifying an appropriate set of terms and conditions that could be imposed upon a merger that would accelerate the deployment of next-generation technology and services in secondary markets served by the merged entity

- Policy advisor to a state regulatory agency in an arbitration proceeding between a rural local exchange carrier and a prospective competitor Emphasis was on determining the merits of a request to remove rural exemption authority granted under the Telecommunications Act of 1996. Responsibilities included establishing a procedural framework, evaluating evidence presented in the proceeding, identifying additional discovery requirements and drafting proposed arbitration agreements for consideration.

- Directed a comprehensive evaluation of the national accounts marketing program for a multi-national telecommunications premise equipment (CPE) manufacturer. The engagement encompassed customer selection, participation and evaluation criteria as well as competitor, market, product and distribution channel assessments.

- Directed a major account marketing program assessment for a leading American telecommunications services provider. The engagement sought to establish the

suitability of current operational systems and planning methods to the needs of major accounts.

- Directed a national accounts marketing evaluation for a leading interexchange telecommunications services provider (IXC). The engagement focused on the establishment of new customer selection criteria and program participation benefits.

- Directed development of a comprehensive national accounts marketing strategy for a major manufacturer of telecommunications equipment The engagement sought to improve upon existing market strategies and customer expectations. Program emphasized participation criteria, expanded customer service and improved emphasis on program profitability.

- Directed a focused examination of the sales and marketing practices of a major telecommunications services provider. The purpose of the engagement was to assess the current level of effectiveness of the direct and indirect sales distribution channels available to the company. It also sought to determine the compliance level of current approaches with state and federal requirements.

- Directed a focused examination of the customer services practices of a major telecommunications services provider The purpose of the engagement was to evaluate the value of current corporate practices regarding service establishment, repair and collection activities to the achievement of corporate service goals. The engagement also sought to determine the business unit's compliance with PSC-mandated service standards

- Directed an assessment of the policies and practices relative to serving the interexchange carrier community. The purpose of the engagement was to determine the suitability of its current provisioning and pricing practices; and represent those conclusions in an FCC inquiry. The engagement included evaluations of current management practices, customer perceptions and facility performance

- Directed a focused review of the telecommunications requirements for a major international currency trading operation. The engagement emphasized the need to integrate independent information networks into a highly responsive and reliable trade fulfillment system. The engagement entailed product evaluation, specialized software development and competitive vendor evaluations

- Directed a focused examination of the customer services operations of a major bankcard fulfillment center The engagement focused on identifying technological enhancements to current customer fulfillment processes and competitive advantages afforded the client by changes in its operations.

- Directed a functional evaluation of ISDN applications available for delivery by emerging telecommunications services providers. The engagement was performed for a major mutual fund firm to better evaluate competing investment opportunities.

- Directed development of a strategic retail marketing strategy for a combination electric/gas utility company designed to maximize the retail market opportunities for their products and services The engagement included market segmentation, application development and delivery channel definition.

- Directed development of a strategic market assessment for a Midwest electric utility The engagement entailed developing an application portfolio for resource allocation and a series of regulatory representations to secure regulatory support for new corporate marketing initiatives.

- Directed a comprehensive market evaluation of the current/proposed commitments to fiber optics business initiatives by a major electric utility company. The engagement sought to establish the potential market value represented by the company's fiber-based telecommunications network as an underlying infrastructure component for interexchange telecommunications services providers

- Special advisor to an American headquartered, multi-national telecommunications firm in its pursuit of European joint venture partners in the EU. Emphasis was directed at delineating the roles and responsibilities of the respective parties for technical and managerial leadership.

- Special advisor to a London headquartered telecommunications firm in matters of FCC compliance and Congressional initiatives. Provided assistance to senior U.S., U.K. and H K managers on identifying probable changes in regulatory and legislative policy regarding U.S. market entry and participation.

- Special advisor to a European telephone operator in matters of affiliate interests and joint ventures with U.S. and U K. directory publishing firms. Special emphasis was placed on satisfying EU competition requirements and partner expectations.

- Special advisor to a European telecommunications services provider in development of a US market entry strategy. Emphasis was directed at determining whether a "buy" or "build" strategy afforded the client the best long-term means of participation in the US market.

- Special advisor to a European development bank in a comparative evaluation of telecommunications infrastructure proposals from central and eastern European governmental agencies. Assistance was provide to help match available development capital to projects that presented both reasonable prospects of profitability and broad market impact in the host country.

- Special advisor to a global telecommunications services provider evaluating competing offers to merge or acquire the Hong Kong-based telecommunications assets of the client. Assistance was directed at identifying -- and helping evaluate –

issues associated with each of the respective offers and the risk presented to shareholders attendant by those issues.

- Special advisor to a European telecommunications services provider in a proposed cross-border acquisition of another multi-line telecommunications services provider. Assistance was provided in identifying an appropriate organizational structure for the combined entity

- Special advisor to an EU-based telecommunications services provider seeking "landing rights" for its submarine telecommunications cables. Assistance was provided developing a negotiating strategy, valuing the rights sought and identifying the appropriate negotiating parties in Latin America, India and Asia.

- Directed development of a market entry strategy for a joint cellular services venture in Europe by an Asian telecommunications services provider Emphasis was devoted to identifying market segments, establishing product packages and coordinating execution of the resultant entry strategy.

- Directed a sales and marketing evaluation of a leading European telecommunications services provider. The study sought to identify weaknesses in market strategies and tactics that resulted in less than forecasted performance by the respective business units. The engagement encompassed policies, practices, procedures, products and programs that affected the performance of the sales and marketing organizations

- Directed development of a Pacific Theater market entry strategy for a major international telecommunications holding company Emphasis was placed on identifying competitor threats, evaluating privatization benefits, establishing product risk thresholds, analyzing regulatory bias and reform measures.

- Directed development of an alternative international network termination strategy for a European record carrier in the advent of economic union in Europe. The purpose of the study was to evaluate proposed changes in European Community rules and regulations on network operating costs and pricing The engagement involved extensive negotiation with governmental agencies, competitors and customers.

- Directed an evaluation of telecommunications investment opportunities in Europe for a major US investment bank firm. The engagement entailed competitive/competitor analysis and market opportunity evaluation

- Directed development of a reorganization strategy for a major international telecommunications holding company. Emphasis was placed on identifying essential corporate responsibilities in the coordination and control of resources allocated to the subsidiary business units. The primary objective of the engagement was to make the corporation more market-responsive and to maximize opportunities presented by cross-product applications.

- Directed an examination of the cost allocation methodologies used by a multi-state telecommunications provider to assign general headquarter costs to its respective state operations. The purpose of the engagement was to determine the appropriateness of current processes and propose changes that would represent improved equity to all parties.

- Directed a comprehensive examination of the proposed infrastructure commitments of a major telecommunications firm. The engagement focused on the scale and scope of technological commitment, the associated need for – and value of – such services to the public and identifying the most appropriate methods of funding such improvements

- Directed an assessment of the financial and managerial value of corporate services offered to subsidiary business units of a major telecommunications provider The purpose of the engagement was to identify the value of such services from the perspective of the beneficiary and represent that value in subsequent regulatory proceedings.

- Directed a managerial assessment of the operational structure of a major independent telecommunications service provider The purpose of the engagement was to identify the impact of the current operational structure on the provision of service The scope of the engagement encompassed all major delivery system components that affect product cost, quality and availability

- Directed a compliance audit of the network modernization and improvement expenditures of a local exchange carrier on behalf of a state regulatory agency. The purpose of the engagement was to ensure compliance with rules, regulations and requirements set forth by the Universal Service Administration Corporation for recipients of universal service support The audit entailed a rigorous examination of the sources – and uses – of funds designated for network investment.

PROFESSIONAL PRESENTATIONS

National Association of Regulatory Commissioners "Structure as Strategy: The Use of Structural Separation as a Strategic Advantage" Washington, DC

National Association of Regulatory Commissioners "Affiliated Interests: A Structural Approach" Albuquerque, New Mexico

National Association of Regulatory Commissioners. Structure as Strategy: The use of Affiliate Relationships to Gain a Regulatory Advantage" Washington, DC

National Association of Regulatory Commissioners "The role of the Regulator in Mergers & Acquisitions" Boston, Massachusetts

National Association of Regulatory Commissioners "RHC Strategic Planning – A Regulatory Perspective" Salt Lake City, Utah

National Association of Regulatory Commissioners "Ethics in Utility Marketing" San Antonio, Texas

International Telecommunications Union "Perils of Privatization: Investing in the PTT's of the COMECON" Geneva, Switzerland

COMECON Telecommunications Development Symposium "Privatization and Cooperation in European Telecommunications Planning" Sofia, Bulgaria

Institute of Public Utilities "Fiscal Fitness: The Capital Crisis Facing the American Utility Community" Tampa, Florida

Institute of Public Utilities "Broadband. Moving Ever Closer to the Goal" Tampa, Florida

Institute of Public Utilities "What Do They Know That We Don't? Changes in the Global Mergers & Acqusitions Arena" Charleston, South Carolina

United States Department of State Country Briefing "Russia: Opportunity or Illusion in Telecommunications?" Washington, DC

United States Department of State Country Briefing "Investing in Sub-Saharan Africa. Wasteland or Watershed? Washington, DC

Overseas Private Investment Corporation Country Briefing "Russia: Opportunity or Illusion in Telecommunications? Langley, Virginia

Prism Research Seminar "Pluralistic Infrastructure Implications to the Incumbent Local Exchange Carrier Community" Boston, Massachusetts

Securities Industry Analysts of America "The Future of Long-Distance Resale" New York, New York

Securities Industry Analysts of America "Local Service Competition: Commoditizing the Telecommunications Industry" New York, New York

TeleStrategies "Local Service Resale: LEC Costing Considerations and Resale Economics" Washington, DC

Telecom Publishing "Private Networks: Liability or Asset to Facilities-based Carriers?" Washington, DC

Financial News Network "The Impact of Divestiture on Investment Risk in the Telecommunications Industry: A Reappraisal" Los Angeles, California

Georgia Public Broadcasting "Equal Access – Its Meaning to the Public" Atlanta, Georgia

League of Women Voters "Town Meetings on Equal Access" Boston, New York, Denver, San Francisco, Chicago, Atlanta, Washington, Miami

American Gas Association "Marketing Customer Service. The New Differentiator" Miami, Florida

AGA-EEI Information Systems Committee – "Managing New Technology" Dallas, Texas

Institute of Gas Technology "Cost Containment in Formulating a Labor Negotiation Strategy" Chicago, Illinois

Edison Electric Institute "Managing Performance Expectations" San Francisco, California

Northwest Electric Power Association "Electric Marketing: A Lesson from the Telecommunications Industry" Portland, Oregon

United States Telephone Association "Affiliate Interests· Boon or Bane to Regulatory Reform" Tampa, Florida

APPEARANCES

California Public Utilities Commission
Directorate Generale IV of the European Union
Florida Public Service Commission
Hawaii Public Service Commission
Illinois Commerce Commission
Indiana Public Service Commission
Infocom Development Authority – Republic of Singapore
Ministry of Information – Republic of Slovenia
New York Public Service Commission
Office of Telecommunications Policy for the United Kingdom
Office of the Telecommunications Authority – Hong Kong SAR
Permanent Court of Arbitration at The Hague
Regulierungsbehorde für Telekommunikation und Post – Deutschlande Republic
Texas Public Utility Commission
United States Senate Sub-Committee on Nuclear Oversight
Virgin Islands Public Services Commission
Virginia State Corporation Commission
Wisconsin Public Service Commission

PUBLICATIONS

"Affiliate Relationships – Strategic Imperative or Regulatory Impediment?" **Public Utilities Fortnightly** June 21, 1990

"Directory Publishing. Affiliating for Advantage" **Public Utilities Fortnightly** December 1, 1991

"Structure as Strategy Achieving Advantage with Organization" (publication pending)

"Governing in the Grey: The Changing Dimensions of Board Membership" (publication pending)

PROFESSIONAL EMPLOYMENT

Managing Vice President and co-founder of Gorham, Gold, Greenwich & Associates LLC – a private management consultancy practice.

The firm is a multi-disciplined organization formed to assist clients in reconciling corporate commitments to shareholders with public expectations and regulatory obligations. The firm provides professional management services integral to achievement, leadership and regulatory compliance. Clients are domestic and international services providers, regulatory agencies, investment bankers, legal firms, institutional fund managers and private network operators.

Vice President and telecommunications industry practice head of Theodore Barry & Associates – a management consulting firm specializing in the regulated utilities field.

The firm – subsequently acquired by PHB Hagler Bailly – is one of the largest management consulting firms specializing in regulated utilities. Responsibility for developing and managing the firm's telecommunications industry practice as well as providing specialized assistance to energy-based clients engaged in merger/acquisition activity and strategic planning initiatives. Clients were both domestic and multi-national telecommunications services providers, national telecommunications agencies and telecommunications equipment manufacturers in a number of related industries. As one dimension of the firm's utility practice a considerable effort was made to develop synergies between the firm's established electric and natural gas practice areas and the telecommunications segment. A bridging strategy was developed using the firm's management audit practice. A number of were performed on behalf of state regulatory agencies over a five-year period. These included the –

Alabama Public Service Commission
Colorado Public Utilities Commission

Connecticut Department of Public Utility Control
Kentucky Public Service Commission
New York State Public Service Commission
Pennsylvania Public Utility Commission
West Virginia Public Service Commission

Finally, a management fitness report was developed of the National Association of Regulatory Utility Commissioners ("NARUC") headquarters staff operations on behalf of the executive committee of NARUC.

Executive Director – Strategic Planning for Allnet Communications Services – a facilities-based interexchange carrier providing telecommunications services in the domestic and international markets.

The position was directly accountable to the Chairman of the Board of Directors Duties and responsibilities associated with this position included strategy development, acquisition identification, legislative/regulatory/media relations and business development initiatives. Additional responsibilities included development and delivery of expert testimony in various certification proceedings, regulatory inquiries and corporate litigation matters.

Executive Director – Strategic Planning for AT&T Corporation – a multi-national telecommunications services and equipment provider.

Headquarters staff responsibility working for the Vice Chairman. Responsibilities encompassed directing strategy development for corporate sales, marketing, diversification, international business development and strategic acquisitions during 10 years of employment. Integrally involved in non-regulated subsidiary development following Computer Inquiry II rulings and agreement to the Modification of Final Judgment rulings. Professional experience during this period included

-structural transition planning
-organizational definition and segmentation
-enhanced product distribution channel definition
-transfer pricing strategies
-regulatory approval strategies
-national accounts program development
-non-regulated market entry strategy development
-international affiliate development
-technology allocation strategies

Ryan Charles Mann
Principal
Consulting Vitae

EDUCATION

BA	--	University of Central Florida
MA	--	University of Nebraska
MBA	--	University of Kansas
CMS	--	Southern Methodist University

AREAS OF SPECIALIZATION

Corporate strategy, strategic product planning, acquisition and merger analysis, organizational strategy and design, strategic market planning, regulatory strategy

CONSULTING EXPERIENCE

- Developed an investigative framework for use by a regulatory agency in examining a request for regulatory relief from specific federal interconnection requirements embodied in Sections 251 and 251 of The Telecommunications Act of 1996. Project entailed identifying informational requirements, establishing regulatory tests and ensuring compliance with all evidentiary rules.

- Assisted in the development of a market entry strategy for a joint cellular services venture in Europe by an Asian telecommunications services provider. Emphasis was devoted to identifying market segments, establishing product packages and coordinating execution of the resultant entry strategy.

- Assisted in a sales and marketing evaluation of a leading European telecommunications services provider. The study sought to identify weaknesses in market strategies and tactics that resulted in less than forecasted performance by the respective business units. The engagement encompassed policies, practices, procedures, products and programs that affected the performance of the sales and marketing organizations.

- Assisted in the development of a Pacific Theater market entry strategy for a major international telecommunications holding company. Emphasis was placed on

identifying competitor threats, evaluating privatization benefits, establishing product risk thresholds, analyzing regulatory bias and reform measures.

- Assisted in a comprehensive examination of a proposed business diversification plan (ie. creation of a competitive access provider network from the client's core fiber optic network) of a major electric utility. The engagement emphasized proper definition of core telecommunications competencies, identifying competitive advantages and establishing a basis for differentiation from other CAPs.

- Assisted in the development of an affiliate risk assessment position statement for a major investment banking firm engaged in telecommunications merger and acquisition activity. The purpose of the engagement was to establish a mechanism for evaluating incremental contribution potentially derived from current or proposed affiliate relationships.

- Assisted in a compliance audit of the network modernization and improvement expenditures of a local exchange carrier on behalf of a state regulatory agency. The purpose of the engagement was to ensure compliance with rules, regulations and requirements set forth by the Universal Service Administration Corporation for recipients of universal service support. The audit entailed a rigorous examination of the sources – and uses – of funds designated for network investment.

- Developed a market entry strategy for a private carriage operator of broadband infrastructure. The purpose of the strategy was to identify means of diversifying the company's revenue streams and re-employ excess capacity in its extant network. The engagement entailed significant empirical research and market identification exercises.

PROFESSIONAL EMPLOYMENT

Product Manager – Alcatel Network Systems. Responsibilities included product and market analysis, product strategy evaluation, product acquisition initiatives and marketing support

Marketing and Product Manager – Tekelec, Inc. Product profitability responsibilities for Signal Transfer Point ("STP") product line Developed a full range of collateral materials and tools for use by Tekelec sales representatives Coordinated research and development work with Bell Communications Research.

Product Analyst -- Illuminet Communications. Responsibilities for analyzing product line for profitability. Proposed changes to product capabilities, pricing and service terms to improve profitability. Provided advice and counsel to sales representatives on technical merits of the product and its performance relative to competitive offerings.

Aaron James Mann
Principal
Consulting Vitae

EDUCATION

BA -- Graceland College
JD Creighton University

AREAS OF SPECIALIZATION

Mergers & acquisition, regulatory compliance, regulatory strategy, intellectual property, corporate governance, executive success

CONSULTING EXPERIENCE

- Provided procedural advice and counsel to a regulatory agency implementing changes to the current rules and regulations governing incumbent telecommunications services provider. Responsibilities included reviewing all procedural motions filed with the agency in the proceeding, evaluating the merits of the request and drafting proposed actions on behalf of the agency.

- Advised a multi-national telecommunications services provider on a proposed U.S acquisition. Responsibilities included a review of foreign ownership rules and development of a compliance plan for consideration by the Board of Directors prior to pursuit of the acquisition

- Assisted in an evaluation of an affiliate relations strategy on behalf of an international telecommunications company. Responsibilities included identifying areas of non-compliance with prescribed state and federal judicial opinions. Extensive research was conducted on relevant case law and briefing papers were developed for use by client representatives.

- Assisted a regulatory agency in conducting an arbitration proceeding between two certificated services providers. Initial responsibilities included establishing an acceptable procedural framework for examination – and resolution -- of the issues. Subsequent responsibilities included reviewing the evidence on behalf of the Hearing Examiner, advising the Hearing Examiner on appurtenant evidentiary rules and providing comment to the Hearing Examiner's written draft opinion.

- Assisted in a compliance audit of the network modernization and improvement expenditures of a local exchange carrier on behalf of a state regulatory agency. The

purpose of the engagement was to ensure compliance with rules, regulations and requirements set forth by the Universal Service Administration Corporation for recipients of universal service support The audit entailed a rigorous examination of the sources – and uses – of funds designated for network investment

- Performed a due diligence evaluation for the Board of Directors of a not-for-profit optical network operator The purpose of the engagement was to examine the legal issues that will define the scope and scale of any revenue diversification initiative that might be approved by the Board of Directors and recommend an appropriate course of action. The engagement entailed a thorough review of tax issues, carrier classification "triggers", right-of-way authority and contract carriage rules.

- Assisted a regulatory agency in conducting an investigation of financing initiatives employed by a local exchange carrier The purpose of this investigation was to determine if the financing methods -- and financial instruments – used by a regulated telephone company comport with applicable rules, regulations and requirements. Emphasis was placed on determining the extent to which any unwarranted risk was assumed by telephone company subscribers as a result of the plan components

- Assisted a regulatory agency in a review of available statutory authority following remand of FCC rules and regulations governing local exchange carrier competition. The purpose of this engagement was to identify the legitimate scope of regulatory authority available to the client under state statute to require competitor access to an incumbent's infrastructure Emphasis was directed at distinguishing between expressed and implied authority as the basis for any action. Work products for this engagement included opinions and case law support for those opinions

PUBLICATIONS

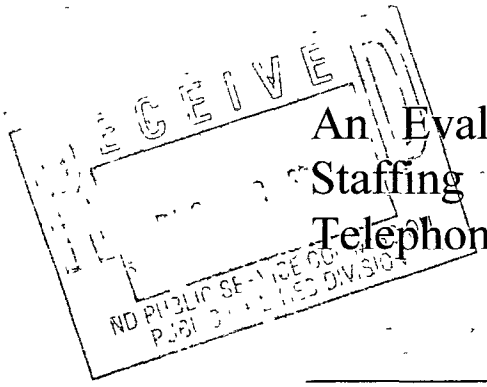
"Challenging the Bright Line: The Role of Regulators in Matters of Corporate Governance" (publication pending)

PROFESSIONAL EMPLOYMENT

Senior Associate – Sonnenschein, Nathan & Rosenthal -- A member of the firm's corporate litigation staff. Handled complex litigation principally in matters of international merger and acquisition, intellectual property and trademark infringement actions.

Law Clerk -- United States District Court for Western Missouri District -- law clerk for the Senior Judge for Western Missouri. Responsibilities included reviewing all procedural matters and drafting proposed rulings on behalf of the judge, ensuring all rules of evidence were complied with by parties and drafting judiciary opinions on behalf of the Senior Judge.

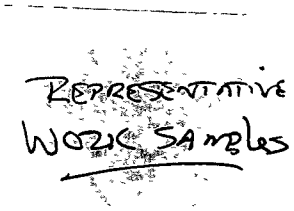
Prosecutorial Assistant -- United States Attorneys Office -- assistant to a group of prosecuting attorneys specializing in federal drug enforcement actions Responsibilities including identifying and developing evidence in support of prosecutorial efforts Additional responsibilities included developing cross-examination strategies for prosecutors, preparing witnesses for appearances and assisting in preparation of briefs, reply briefs and summary presentations by senior prosecutors.



An Evaluation of St. Croix Central Office Staffing Policies and Practices by Innovative Telephone Company

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Prepared for
The Virgin Islands Public Service Commission
November 3, 2004


REPRESENTATIVE
WORK SAMPLES

Virgin Islands Public Service Commission
E911 Public Safety Practices
Staff Report

Problem Statement

It has been suggested that certain staffing practices employed by Innovative Telephone Company leave the St. Croix Central Office ("St Croix CO") unmanned at certain times of the day and week. It is further suggested that during those times when skilled technicians are not on duty in the St. Croix office that the integrity of the E911 public safety systems used on St. Croix is placed at risk. According to claimants, this presents a potentially dangerous situation if any problems arise in the St Croix office that might require the immediate attention of a trained technician. The fact that E911 service for St. Croix is dependent upon the St. Croix Central Office for communications should be, in the opinion of these claimants, sufficient reason to require Innovative to ensure the St. Croix Central Office is staffed all the time.

This matter has been raised before the Virgin Islands Public Service Commission ("VIPSC" or "Commission") on several occasions in several different forums. In each instance, the claim has always been raised by employees of Innovative Telephone Company and/or representatives of their collective bargaining unit. To date, no other party (e.g., public safety agencies, elected officials or health professionals) has raised the issue in any proceeding before the VIPSC or echoed support for the claim made by Innovative employees and their union

The claimants offered no evidence to support their claim that Innovative's staffing practices in St. Croix constitute public endangerment. However, the Commission elected to examine the matter further to be certain that the methods employed by Innovative in support of public safety agencies by on St. Croix is consistent with the company's responsibilities under 47 C.F.R. § 64.3001 and 47 C.F.R. § 64.3002.[1]

Purpose

It bears repeating that no evidence has ever been offered to support the claim that serves as the basis for this examination -- although it has been brought forth on repeated occasions by the union seeking Commission action. The lack of an evidentiary record has impaired the ability of the Commission in the past to properly dispense with this matter whenever it has been raised. After entertaining the claim again at a recent Commission meeting it was decided by the Commission to give the matter further examination before

[1] 47 C F R § 64 3001 specifically requires that all telecommunications carriers shall transmit all 911 calls to a Public Safety Answering Point, to a designated statewide default answering point, or to an appropriate local emergency authority as set forth in 47 C F R § 64 3002

rendering any opinion or taking any necessary action. Accordingly, a request was made that an examination be conducted and a report submitted to the Commission for review.

The Virgin Islands Public Service Commission directed Gorham, Gold, Greenwich & Associates to examine the matter on its behalf and submit a report of its findings for formal consideration. Lacking any evidence to support the claim, and with no opinion on the merits of it, the Commission elected to forbear from prescribing a scope of work or a level of effort. Instead, the Commission chose to let the consultant assume responsibility for both matters. This submission represents the sum of our effort on behalf of the VIPSC to fully examine the claim presented to the Commission and fairly evaluate its merit. Gorham, Gold, Greenwich & Associates accept full responsibility for the content, conclusions and recommendations presented herein.

Perspective

The most difficult part of any regulatory investigation is deciding what issues merit the attention of the Commission. In this proceeding, the claimants have simply pointed to the fact that Innovative does not man its central office on St. Croix all of the time. The consequence of that practice, they suggest, is to jeopardize the public safety of St. Croix by leaving the E911 system vulnerable to failure.

As a general rule, regulatory agencies do not directly question the staffing practices of the companies that they regulate; instead, they challenge the costs associated with those practices rather than the practices themselves. Staffing matters are generally resolved in negotiations with collective bargaining bodies and codified in labor agreements, work rules and job descriptions. Disputes are generally handled with various types of job actions and resolved with negotiation and, in some cases, arbitration.

The exception to this practice is when it can be shown the company's practices a) contribute to higher than necessary costs or b) deliberately jeopardize the public's welfare and safety. In this instance, no one has suggested that the current staffing practices of Innovative have in any way contributed to higher costs. However, the claimants allege that public safety is potentially threatened and should not be tolerated.

It has been our experience that public safety remains of paramount concern to any regulatory agency – no less so to the VIPSC than to any other. When concerns for public safety are raised, commissions in every instance have been willing to give full and fair hearing to the matter. We find the concerns raised by the union in this matter to be plausible -- and worthy of examination – to determine their relative merit.

The importance of the public switched telephone network to the preservation of public safety cannot be overstated. It is a generally recognized fact that much of our emergency response capability rests upon the proper operation of the public switched telephone network. It is also apparent to everyone that public safety communications constitute one of the most critical applications supported by the public switched telephone network.

For that reason we elected to examine the issues raised by the union not from the perspective that Innovative's labor practices were harmful to employee welfare but rather from the perspective that they presented a risk to the public's safety. We chose to conduct our examination using public safety as the defining issue – and definitive standard – in this matter. It was our opinion that this approach properly reflected the public's interest in this matter and the Commission's responsibilities to that public

In this particular instance, the public's interest is ensuring that the E911 system in St. Croix is available, accessible and reliable. Any policy and/or practice of Innovative Telephone that threatens that interest is sufficient cause for the VIPSC to intercede on behalf of the public. Accordingly, we focused our investigatory attention to the manner in which Innovative Telephone Company currently addresses its E911 service obligations in the territory – and focused our attention on identifying any risk to public safety that those practices present. In that way, we were able to see if the way in which Innovative Telephone Company purportedly manages its responsibilities on St. Croix contribute to the issue raised by the claimant and, therefore present a risk to the E911 system and to public safety.

Following that general approach, Gorham, Gold, Greenwich & Associates conducted a fact-finding exercise with representatives of Innovative Telephone Company construct a base of evidence that would be useful in our evaluation. Simply stated, we employed a conventional three-step forensics-based methodology –

- Identify the policies and practices governing the provisioning of E911 service to the designated Public Safety Answering Point ("PSAP");
- Determine whether those policies and practices comport with VIPSC rules and regulations;
- Conclude whether current service delivery policies and practices present an unwarranted risk to the public and merit reconsideration by the VIPSC

It also bears mention that even though this examination is focused on resolving a specific claim it presents an opportunity for the Commission to amass a body of relevant information that can act as a foundation for future public safety policies. [2] Although the question before the Commission in this proceeding specifically pertains to the level of support provided to certain public safety functions by Innovative Telephone, the Commission's decision to examine this matter further before taking any action constitutes an attempt to fully understand the complexities of this issue before proposing any changes to its current public safety policies or to Innovative Telephone's duties and obligations Therefore, it is important to recognize that the decisions sought in this proceeding have public policy implications much broader than might otherwise be assumed and demand thoroughness and accuracy.

Contextual Framework

[2] Lacking any specific evidence to support the alleged claim, the Commission is obligated to undertake a fact-finding exercise to determine if there is merit to the charge before any remedial action can be taken

As a matter of background, "911" is a set of recognized public safety services prescribed by federal law and administered by designated public safety agencies. 911 affords the public a generally-recognized, universally-accessible, easy-to-remember means of securing assistance from public safety agencies in times of emergency. 911 provides the public a single access-point to emergency dispatchers trained to route service requests to local emergency medical, fire, and law enforcement agencies. 911 relies upon the public switched telephone network for some – or all – of the facilities needed to complete a request for emergency assistance. Consequently, availability to, and reliability of, the public switched telephone network is critical to the ability of the 911 service to meet the public's needs.[3]

In this instance, the Commission is presented with the task of determining if the level of risk attendant to Innovative's approach to supporting 911 services in the territory is consistent with the public's interest in this matter; or if certain measures must be taken to reduce any attendant risk to a level consistent with the public's interest. To measure the risk it is necessary to establish what is the public's interest in E911. It is our opinion that two things are important to the public –

- the assurance that a call placed to 911 will be completed efficiently and accurately; and
- the assurance that a response for assistance from public safety agencies will be prompt and effective.

911 services are publicly-administered safety programs made possible by the cooperation of the telecommunications industry and the technological capabilities that they have deployed within their own infrastructure. The individual functions performed by each of the respective parties – the public safety agencies and the telecommunications industry – are well-defined by law and contractual agreement. Each party is limited by law and contract to performing its part in providing 911 service but is not – and cannot be -- required to assume responsibility for the other party in the case they fail to fulfill their assigned duties and obligations.

It is important to any discussion of this matter to recognize that the FCC rules governing 911 service bisect responsibilities for provisioning the 911 service clearly between public safety agencies and the telecommunications industry. The telecommunications industry is responsible for ensuring a) the 911 service is accessible from any working telephone and b) a call to 911 is properly routed to the responsible Public Service Answering Point. Similarly, the designated public safety agency is responsible for ensuring a) any call to 911 is answered and b) an appropriate response is render to the request for assistance.

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[3] In recent years the foundation for 911 service has been improved and expanded as a consequence of technological improvements "E911" is an industry term that refers to an enriched set of support capabilities that have been made possible and have substantially improved the first-generation systems used to provide 911 service Public safety services in The United States Virgin Islands are generally supported by E911 systems that provide for substantially improved identification and response capabilities For purposes of this report the term "911" will be used consistently to refer to the functional service provided to the public by agencies charged with public and safety while "E911" will be used to designate the technological platform that is used to provide the 911 service

Each of the parties is obligated to fulfill a prescribed set of responsibilities that collectively comprise 911 service It has been made apparent that the scope of the Commission's interest, however, is limited to those responsibilities entrusted by Congress to the telecommunications industry – specifically to Innovative Telephone Company. It is not the intent of the Commission to offer comment on the activities of the territory's public safety agencies except to the degree that such comment is deemed necessary to properly evaluate the performance of Innovative Telephone.

Issue Framework

The challenge presented in this investigation is to calculate the level of risk inherent to processing 911 service requests in the Virgin Islands. More precisely, it is a matter of a) isolating those risk factors that emanate from the policies and practices employed by Innovative for its portion of the 911 service and b) assessing the extent to which those policies and practices engender risk to the process.

Although 911 services require cooperation by public safety agencies with the telecommunications industry the two parties do not "share" responsibility for any function associated with the 911 service request process. Each party performs certain functions and assumes certain responsibilities that are distinct from those of the other party. Points of demarcation between the two party's functional responsibilities are well-defined by rule and contract. The boundaries are well understood and mutually respected. Therefore, it is not only possible to separate the activities performed by Innovative from those performed by public safety agencies it is imperative that we do so if we are to ensure a proper evaluation of the current situation and fair treatment to all of the interested parties.

The structural framework that governs 911 service limits Innovative's role -- and its functional responsibilities -- to performing transport and switching functions necessary to process a 911 service request. Therefore, any evaluation of the support provided by Innovative to 911 service must be confined to those specific areas for which it bears responsibility.[4]

911 Service Responsibilities

As stated at the beginning of this report, 911 Service is a universal – and uniform – means for the general public to secure assistance from public safety agencies in times of emergency. By dialing 911 on any telephone in the Virgin Islands individuals are connected via the public switched telephone network to a Public Safety Answering Point ("PSAP") staffed by representatives of the responsible public safety agencies.

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[4]Risk factors other than those examined in this report exist and present substantive challenges to the functional integrity of the 911 service However, recognizing those risks and assuming they are the responsibility of Innovative Telephone would be unfair Responsibility for any risk associated with 911 service beyond that examined here resides with public safety agencies and equipment manufacturers Such risk is a function of decisions and events that are not within the scope of responsibility assigned to Innovative Telephone Company and, therefore, not subject to review in this examination

911 Service employs a decentralized architecture with two independent E911 systems deployed for St Croix and St. Thomas/St. John. Each of the E911 systems has an associated PSAP located in the police headquarters of the respective communities. The St Croix PSAP is located at Golden Grove and the St Thomas/St. John PSAP is located at the Farrely Justice Complex. All calls placed on Innovative's telephone network to the 911 are routed to the respective PSAP depending upon the originating caller's location via dedicated trunks between Innovative's . At the PSAP the specific nature of the call is determined and routed to the responsible agency by employees of the Virgin Islands Police Department ("VIPD").[5] All equipment and staff associated with the PSAP are the responsibility of the Virgin Islands Police Department.

Each of the Public Safety Answering Points comprises a switch, a Motorola Centerlink 911 Automatic Number Identification ("ANI") Controller and an IBM processor-based Automatic Location Identification ("ALI") database system Together the ANI and ALI devices provide 911 Service attendants at the PSAP the means to efficiently determine the location and identity of the calling party.[6] These devices -- along with all hardware and software associated with the attendant positions and remote printers at public safety dispatch locations -- are the sole responsibility of the Virgin Islands Police Department and its equipment suppliers. The acquisition and maintenance of all PSAP equipment – as well as staffing of that equipment – is the purview of the responsible public safety agency administrators.

Innovative Telephone functions as an underlying supplier to the responsible public safety agency administrator responsible for 911 Service. In this instance, the Virgin Islands Police Department serves in that capacity and determines any requirements the PSAP has for services from the telephone company. Innovative Telephone functions in a relatively minor role enabling access to the PSAP via the public telephone network.[7]

The VIPD contracts for telephone service from Innovative Telephone that will permit it to connect its PSAP to the network. Typical services required by the PSAP include switched access lines, trunks and dedicated circuits for ring-down and data circuits Additionally, Innovative Telephone automatically forwards certain call processing data that "trigger" the ANI Controller and ALI database maintained and operated by the PSAP.

The decentralized approach to 911 service adopted by Virgin Islands public safety agencies affords a "bright line" between responsibilities borne by Innovative and the PSAP

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[5] 911 Service Attendants employed by the VIPD handle all requests received at the PSAP for police assistance Emergency services requests for assistance from the fire department or hospital may be transferred to the responsible agency

[6] ANI enables display of a caller's telephone number on a PSAP attendant's console The ALI database stores the physical location associated with the listed telephone number and forwards the information to a PSAP attendant's console ALI daily updates are required to ensure continuity between the ANI information and ALI database Daily updates are not currently provided by Innovative due to a lack of necessary hardware and software in the PSAP equipment employed by the VIPD

[7] Innovate does not function as a PSAP tandem in the 911 Service architecture deployed by Virgin Islands public safety agencies, therefore, its role is limited to providing switching and transport support via Nortel DMS 100 central office switches to the respective PSAP on St Croix and St Thomas

administrators. The public safety agency-operated PSAPs are connected directly to Innovative Telephone's network via voice-grade trunks with in-band signaling thereby obviating the need for complex service control points at defined demarcation points at Golden Grove and the Farrelly Justice Complex. All calls directed to 911 are transported by Innovative's public network to the primary PSAP responsible for their area and then extended by PSAP personnel to the appropriate emergency service agency as determined by PSAP personnel. Call identification, evaluation and disposition is the sole responsibility of the PSAP and entails no involvement by Innovative Telephone.

Any extraordinary event that requires deviation from the standard call processing protocol established by the PSAP administrators and Innovative Telephone Company entails notification and agreement between the two parties to employ a secondary protocol. Such events may include equipment failure, power losses, bomb threats and/or flooding at the PSAP.[8] In the event of any failure in 911 system used by the PSAP a representative of the public safety agency notifies the designated representative of Innovative of the condition and instructs the Innovative representative to re-direct requests for 911 service to a designated location. Re-directing traffic destined for either of the PSAPs to a secondary answering point entails manual intervention and is initiated by Innovative only after receiving specific instructions from the PSAP representative The process is relatively simple, can be completed in a matter of minutes and can be implemented from either of the host serving offices using remote access technology.

As noted earlier in this report availability to -- and reliability of -- the public switched telephone network is critical to the ability of the 911 service to meet the public's needs.[9] As can be seen in the above narrative the designated public safety agency bears responsibility for determining the type and number of telecommunications services required to support the PSAP's call volume.[10] Once the identified requirements are determined by the PSAP administrators to be sufficient to its needs, Innovative Telephone assumes responsibility for ensuring the designated facilities – and those portions of the public switched network connecting to those facilities -- are available for use and reliable.

- Innovative Telephone Company is not immune to the possibility that extraordinary events could disrupt its ability to successfully process requests for 911 service. Equipment failure, cable cuts, water damage, power

[8] For purposes of this report we will not consider the possibility or consequences of these types of events because they relate to situations not within the control of Innovative Telephone and thus outside the scope of the Commission's interest It is sufficient to note that such events a) have occurred and b) have required implementation of previously agreed upon protocols to ensure 911 service continuity is not compromised

[9] In recent years the foundation for 911 service has been improved and expanded as a consequence of technological improvements "E911" is an industry term that refers to an enriched set of support capabilities that have been made possible by technological advances and have substantially improved first-generation systems used to provide 911 service Public safety services in The United States Virgin Islands are generally supported by E911 systems that provide for substantially improved identification and response capabilities For purposes of this report the terms "911" or "911 service" will be used consistently to refer to the functional service provided to the public by agencies charged with public and safety while "E911" or "911 systems" will be used to designate the technological platform that is used to provide the 911 service

[10] Innovative Telephone measured recent call volume to the St Croix and St Thomas PSAP for a 14-hour period (9 00AM-12 00Midnight) and determined that its equipment transported an average of 30 calls per hour to the St Croix PSAP and 29 per hour to the St Thomas/St John PSAP

failures, fire and sabotage present recognized threats to the operational integrity of Innovative's public switched network – and to 911 service supported by that network. Innovative has instituted precautionary measures and adopted higher equipment standards in an effort to mitigate, if not eliminate, any threat to its network – be that threat in its Central Offices or its outside plant facilities.

In the specific instance of 911 Service, the potential for failure rests in two areas – the loss of switching capability in the serving Central Office and the loss of a dedicated trunk from the serving Central Office to the PSAP. In both instances, the affected PSAP is left without connectivity to the calling party. However, the PSAP retains independent means to communicate with other public safety agencies -- and Innovative Telephone -- via radio and wireless communications networks. These networks provide the means to notify the affected agencies of their present disposition and coordinate secondary response strategies. These alternative communications networks available to the PSAP ensure public safety agencies are prepared to handle direct requests for emergency services and the public is relatively inconvenienced by any temporary loss of connectivity.[11]

Trunkage

In the event Innovative were to experience trunk(s) failure in the network between the serving CO and the PSAP one of several contingency strategies will be executed depending upon the root-cause of the failure. In those instances where –

- Central Office Equipment ("COE") supervisory software detects the problem and "busies out" the affected trunk(s) thereby temporarily removing it from the PSAP's dedicated trunk group and forwarding 911 calls to the next available trunk in the group. In such an instance, an internal error report is issued and a repair work order is initiated to restore the trunk to operational condition. The loss of trunk availability is generally not apparent to the end-user and requests for 911 service are processed without any appreciable delay in completion.

- A telephone company technician, a PSAP administrator or a third-party encounters a problem and reports an "out of service" condition to Innovative the affected trunk(s) can be manually "busied out" and temporarily removed from the PSAP's dedicated trunk group. In this instance, the manually reported outage initiates a repair work order to identify the problem, remove the affected trunk(s) from the available trunk group and undertake measures to restore the trunk to operational condition.[12] The loss of trunk availability may be apparent to end-users until

[11] Current provisioning models employed by Innovative provide for almost half of the E911 trunks to be unavailable for use without adverse impact on the ability of the PSAP to handle projected volume of requests for 911 service

[12]Temporary removal of an affected trunk ("busying out") can be accomplished for trunk groups either a) by technicians on-site at the serving Central Offices or b) via remote access from another CO when the affected

such time as the trunk is manually removed and continuity is restored to the affected trunk group. The length of any disruption is a function of the time it takes for the outage to be reported and the appropriate response executed by Innovative [13]

Central Office Equipment

A loss of switching capability at a serving Central Office presents a more significant operational challenge to Innovative -- and to 911 service -- than that created by any loss of trunk facilities. For that reason, risk mitigation strategies generally employed by the telecommunications industry emphasize preventive measures designed to reduce the probability of COE failure rather than response mechanisms. The industry has consistently required COE manufacturers to clearly demonstrate the ability of the products to achieve reliability levels exceeding 99.999% under controlled operating conditions.[14]

In response to this performance standard, manufacturers have adopted network topologies and architectures that approach totally fault-tolerant systems. Specifically, manufacturers employ –

- redundant central office processors that provide real-time backup in case of a switch failure, and
- supervisory software that continuously monitors network performance and automatically activates secondary systems and sub-systems

The systems in-depth methodology is a general component of every established manufacturer of "carrier-class" equipment seeking to market to the telecommunications industry.[15] In the case of Innovative, switching equipment used in both serving COs (St. Croix and St. Thomas/St. John) is conventional circuit-switched technology manufactured by Nortel.[16] Similar equipment is deployed throughout North America as part of the infrastructure of virtually every common-carrier. Nortel is viewed as a premier technology

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CO is not currently manned There is no appreciable difference in effect or time between remote interdiction and human interdiction

[13] In instances where trunk outages are not automatically identified the duration of any outage condition will be longer due to the need for human interdiction Any recognized effect on 911 call completion is inconsequential -- unless the entire trunk group is affected by the outage – due to engineering practices of Innovative that provide for excess trunk facilities to pickup any residual effect of an out of service trunk condition

[14]This equates to one outage of one-hour duration roughly every 11 42 years of its operational life

[15]The engineering standards applied by manufacturers to equipment used in the PSAP by public safety agencies were not examined in this report because of the limited interest -- and jurisdiction – of the VIPSC. It is assumed for purposes of this study that the equipment used by the Virgin Islands Police Department meets any required performance standard set forth by the FCC Any incident of failure attributable to PSAP equipment is not within the scope of responsibility borne by Innovative Telephone and, therefore, not a subject of this evaluation

[16] The St Croix and St Thomas PSAPs are independently served by DMS-100/200 local switching systems equipped with software release NA015 Additional software releases are available for commercial use but have not been scheduled for introduction by Innovative at the time of this report A preliminary review of the most current software release does not suggest the enhancements will materially reduce the probability of switch failure beyond that afforded by the current software release used by Innovative

vendor; its equipment is viewed as both efficient and reliable. Nortel actively monitors the performance of its installed based of systems and systematically manages product enhancements. To date, the DMS100/200 has no history of systemic vulnerability that would suggest Innovative's decision to deploy these systems in support of its public switched network – and by that decision 911 service – is anything but reasonable and proper.

We have seen nothing in Innovative's choice of switch technologies – or switch vendors -- to suggest that the level of risk to 911 service in the Virgin Islands is any different than the risk presented to providing 911 service by any other local exchange carrier; that is is to say, negligible. However, that does not mean that a switch failure is not possible; only that failure attributable to the technology itself is negligible. Innovative further reduces the risk of any failure attributable to technology by continuously monitoring and systematically interrogating each of its DMS100/200 systems to ensure maximum performance.[17]

Exogenous events such as those discussed earlier remain credible possibilities although remote possibilities. In the unlikely event that a central office failure is experienced the PSAP served by that central office will lose all connectivity with the public switched network until restoration can be fully completed. Under such a scenario 911 calls destined for the associated PSAP cannot be completed or rerouted by Innovative. The estimated length of any such outage is indeterminable depending wholly on the nature of the failure, the extent to which the failure is part of a larger set of events (e.g.., natural disaster, terrorist act, war, civil disturbance, etc) and the level of effort required to restore service. Such events present an element of risk to the operational integrity of the 911 system; however, the statistical probability of such an event actually occurring is extremely low and beyond the ability of Innovative to completely eliminate. Recognizing the challenges that such events present to operational managers, Innovative maintains a disaster recovery plan that provides for a calculated and managed response to any catastrophic event – which a total failure of a central office for any reason must be viewed.

In the event a catastrophic central office failure occurs in one of the offices supporting a PSAP all 911 calls destined for that PSAP would be immediately redirected to the remaining PSAP and/or other answering points designated by public safety officials Redirection, however, would be an event-driven decision undertaken by Innovative personnel at the direction of the public safety officials. There is no automatic rerouting possible in such cases and the public would experience some disruption until call-handling arrangements are finalized at a secondary answering location. The extent to which any disruption if experienced would be related to the time it takes public safety officials to arrange for a secondary answering point and staff it.

If it were determined that in the event of a central office failure all 911 calls should simply be redirected to the remaining PSAP the current engineering practices of Innovative

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[17] Innovative employs on-site technicians in the St Croix Central Office from 8am-12midnight on weekdays and 8am-5pm on weekends The St Thomas/St John Central Office is staffed around the clock A Maintenance Administration Position ("MAP") located in the St Thomas CO permits technicians to continuously monitor – and administer changes to – the St Croix office when it is not staffed The MAP provides the means to achieve continuous cost-effective surveillance of both offices during periods of minimal order activity and maintenance work

provide reserve trunks adequate to accommodate the additional calls without any degradation in call completion performance.[18]

Conclusions

The question posed for consideration in this investigation has been whether or not the Virgin Islands Public Service Commission should direct Innovative Telephone to revise its current staffing policies to provide full-time coverage in the St. Croix Central Office It has been suggested that the current practice of leaving the St Croix Central Office unattended for certain periods of time threatens the integrity of the 911 service available to residents of St. Croix thereby jeopardizing the public's safety.

After reviewing the Virgin Islands Code, the FCC rules and regulations governing E911, and the policy opinions issued by a number of other regulatory agencies it is apparent that the VIPSC has sufficient authority to order Innovative Telephone Company to make the change proposed by the union if the VIPSC deems it necessary to do so to protect the interests of the public. However, after a critical review of the information provided by Innovative, the Federal Communications Commission and its equipment providers we find no evidence to support the claim that public safety is threatened by the company's practices and no need to require additional measures to ensure that safety is preserved in the future.

This investigation represents the most diligent effort on the part of the VIPSC to thoroughly examine this issue. The evidence submitted for examination demonstrated that public safety was not materially jeopardized by the company's policies and practices. Of equal import is that staffing policies and practices employed by Innovative in St. Croix are comparable to those employed across the industry and are deemed acceptable to the FCC. Furthermore, these practices have not been challenged by representatives of the public safety agencies who, in our opinion, have a significantly greater stake in this matter than any organized labor group or body of employees.

We applaud the claimants for bringing their concerns to the Commission. However, nothing that we examined in this proceeding substantiates the claims presented on this matter . On the basis of our examination we must recommend the Commission dismiss this claim and conclude its interest in this matter. In support of that recommendation we offer the fact that our examination found no evidence to suggest that the current practice of leaving the St. Croix Central Office unattended for certain portions of time presents any greater threat to 911 service -- or any greater risk to the public than when it is staffed. Furthermore, we found that while the St. Croix office was "unattended" for periods of time it was not "unsupervised". The operational status of the St Croix central office was

[18] In any scenario where it might be assumed that a single PSAP must perform the dispatch duties currently offered by two centers the level of service provided to requesting callers may experience some degradation as a consequence However, any degradation that might be experienced in such circumstances will more likely be the result of insufficient staff than insufficient trunk group facilities Engineering models provide for practically 100% increase in call volume without jeopardizing the available trunk groups On the other hand, PSAP staffing models are designed to match expected call volume against available staff In the event of a central office failure a substantially larger volume of calls will be directed at the remaining PSAP generating call volumes not tolerable in present staffing scenarios

constantly monitored by Innovative Telephone Company and always subject to remote supervision and control systems. Therefore, the supervisory support provided to St. Croix's E911 is always the same as that provided on St Thomas

Additionally, our review found that –

- Innovative has responsibility only for ensuring the availability – and reliability -- of the public switched telephone network employed by public safety officials for their 911 service;

- Innovative has no responsibility for ensuring the availability – and reliability – of equipment attached to the public switched telephone network and used by public safety agencies to terminate calls for 911 service;

- Innovative has deployed central office systems in support of 911 service that are commercially-proven, highly-reliable and virtually fault tolerant;

- Innovative provides uninterrupted supervision of all central office systems (St. Croix and St. Thomas/St. John) by means of a centralized administrative position in St. Thomas;

- Innovative has never experienced a total central office failure on St. Croix or St. Thomas;

- Innovative "over engineers" trunk facilities needed to support 911 service to ensure against an "all trunks busy" condition;

- Innovative maintains formal protocols with the PSAP administrators that govern any responsive measure taken by Innovative to modify 911 call completion procedures to meet any contingency;

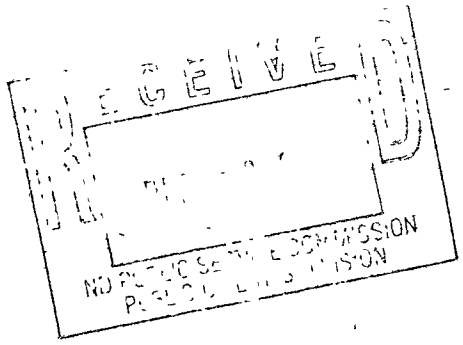
On the basis of these findings, we hold the opinion that the current policies, practices and procedures employed by Innovative Telephone in support of 911 service appear sufficient to meet the expectations of the public and the needs of the public safety agencies of the Virgin Islands. We found nothing to suggest that the absence of full-time technical support in the St. Croix office changes the risk profile of that facility or increases the probability of a system failure because of said absence. In our opinion, the effort made by Innovative Telephone to contain any risk associated with supporting 911 service is sufficient at this time to meet the needs of the public safety agency administrators and, therefore, necessitate no supplemental measures on the part of the Commission.

As in any investigation of this sort the findings, conclusions and recommendations offered in this report are based upon the reviewed evidence. Gorham, Gold, Greenwich & Associates reserves the right to revise and/or rescind these opinions if new evidence is presented that shows the factual basis of this report is in error.

An Evaluation of Submission and Recommended Action Regarding the Universal Service Fund Eligibility Certification Request of Innovative Telephone Company

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Prepared for
The Virgin Islands Public Service Commission
September 3, 2004



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September 3, 2004

The Honorable Valencio Jackson
Chairman
Public Services Commission of the United States Virgin Islands
P O Box 40
Charlotte Amalie
United States Virgin Islands 00804

Dear Chairman Jackson.

This submission is in response to the request of the Virgin Islands Public Services Commission (hereafter referred to as "the VIPSC" or "the Commission") that Gorham, Gold, Greenwich & Associates review the August 1, 2004 request of Innovative Telephone to certify its use of universal service funds made available to it under 47 U S C. § 254(e) Attached is a summary of the analysis performed in this matter

In summary, after reviewing the materials provided by Innovative Telephone (hereafter referred to as "Innovative" or "the Company") and subsequent discussions with representatives of Innovative we are satisfied that the Company is an eligible telecommunications carrier and that support provided by the Universal Service Fund is used in a manner consistent with the stated intent of 47 U.S C. § 254(e). At this time we commend the submission made by Innovative to the VIPSC for consideration and recommend that the Commission reaffirm its' designation as an eligible telecommunications carrier ("ETC") and certify that it has satisfied all of the requirements set forth in Section 254(e)

If, upon review, there are any questions please feel free to contact me at your convenience

Respectfully Submitted,

Gregory Loyd Mann
Managing Vice President

cc. Frederick G Watts, VIPSC General Counsel

Communications Commission was established.[2] That said, however, the concerted effort of the regulatory community and the telecommunications industry to achieve universality remains a daunting task. In recent years, the base of residential telecommunications users has leveled off despite aggressive efforts on the part of regulatory agencies, industry members, social services departments, philanthropic and educational groups to increase awareness and affordability of telephone service.[3]

In the 1990s Congress made a concerted effort to modernize the extant regulatory framework that had defined the telecommunications industry for sixty years. Considerable differences regarding the scope and scale of change required to reconcile six decades of change were readily apparent in the proposed initiatives Despite the differences, however, Congress was intent upon creating a new regulatory regime that would address the challenges of the future without sacrificing the accomplishments of the past.

The 104h Congress adopted The Telecommunication Act of 1996 ("1996 Act") which, amongst other features, provided for changes to its commitment to universal service. Presented with substantive threats to the traditional funding sources for universal service support Congress elected to abandon the implicit support mechanisms traditionally used by the FCC After some debate over the continued need for -- and value of -- universal service support Congress voted to establish a Universal Service Fund ("USF" or the "Fund"). The general commitment to universal service set forth previously in 47 U S.C. § 151 was, for the first time, augmented by specific policies and programs designed to advance the goals originally set by the 73rd Congress.

The enabling legislation contained in the 1996 Act introduced a series of measures designed to ensure continued support for universal service initiatives even as the local exchange market undergoes pervasive – and permanent – changes. More importantly, the 1996 Act created a special support system that levied funding obligations on a large body of service providers and specifically designated a set of tests for prospective beneficiaries. For the first time in its history, the pursuit of universal service was delineated as a universal responsibility – a mission that everyone shared some responsibility for and derived some benefit from. The Universal Service Fund stands as an affirmation of the importance of pursuing universal service to the social and economic fabric of the nation – irrespective of where that pursuit is taking place.

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[2]The Telecommunications Act of 1934 was subsequently amended by actions of the 104th Joint Session of Congress in 1996 The general principle of universal service contained in the 1934 Act was substantially broadened and significantly enriched

[3]An emerging body of thought is that certain demographic groups view wireless telecommunications services as preferable to local exchange services provided by the local telephone company Although the empirical evidence to support this thesis is relatively "thin" and lacks sufficient statistical confidence to support a conclusive opinion. However, we believe it not unreasonable to conclude that wireless services will continue to experience improvement in the future and as such will increasingly present a meaningful alternative (for some group of people) to local exchange services from a telephone company Given that set of circumstances we believe it will be increasingly difficult for regulators and telephone company executives to substantially reduce the number of American households that do not have wireline telephone services below that currently reported – irrespective of what additional measures might be entertained.

Universal Service Fund

a. Purpose

The Universal Service Fund was created by the Federal Communications Commission pursuant to instructions set forth in 47 U.S.C. § 254. The Universal Service Fund is a federally-mandated and federally-administered program. Federal agencies determine eligibility, administer all funding mechanisms and judge compliance.

The stated purpose of the Universal Service Fund is to replace the implicit subsidies historically used to offset the extraordinary costs incurred by local exchange carriers providing telecommunications services high cost areas, to low income customers and other community-centered enterprises such as schools, libraries and hospitals. An expressed goal of the Fund is to provide financial support to those carriers that serve areas that exhibit historically high-cost profiles thereby ensuring that customers in those areas retain access to local telephone services at rates that are fair and reasonable.

The enabling statutes – and the associated FCC rules and regulations – provide a set of policies and programs considered sufficient to meet any foreseen challenges to the pursuit of universal service. The foundation for the new program rests with the explicit funding mechanism that replaces the implicit funding of the past. The 104th Congress understood the immediate need to furnish greater funding protection for the future than had been provided in the past with specific, predictable and sufficient support mechanism. Consequently, Congress sought to substantially broaden the base of funding support for universal service thereby reducing the financial burden on any single set of users and providers and, hopefully, reducing opposition. In the end, Congress concluded that a levy on most telephone customers collected by carriers was the most equitable means of funding its universal service commitment.[4]

By its actions, the 104th Congress effectively transformed financial support for universal service from being the responsibility of a few to becoming the responsibility of all of the nation's telephone services subscribers. In a matter of a few words, universal service was elevated from simply an avowed guideline to a acknowledge guidepost for future public policymakers. For the first time the societal benefit that had long been associated with universal service was recognized to have a universal responsibility associated with it.

The Universal Service Fund represents a self-sufficient support program that draws no financial assistance from the United States Treasury. It is funded solely by means of fees levied on users of the public switched telephone network. Through a series of tests the funds are distributed amongst a series of designated services-providers that have met a series of eligibility criteria. These Eligible Telecommunications Carriers ("ETCs") represent companies that have previously evidenced their willingness – and their ability -- to serve all customers in a high-cost service area to a state regulatory body or to the FCC.

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[4] 47 U.S.C. § 254(b) provides that all providers of telecommunications services should contribute to the fund and that such contributions should be equitable and nondiscriminatory.

After a carrier is formally designated by a state regulatory agency as an ETC it is eligible to request support from the Universal Service Fund If its request for assistance is approved by USAC financial support can only be used to offset the costs of providing those services deemed eligible by federal rules.[5] The responsibility to ensure universal service funds are used only for their stated purposes extends to regulatory agencies as well as to recipient companies Similarly, a state regulatory body may not order a local exchange carrier receiving support from the universal service fund to expend that support on anything other than the facilities and services deemed to be part of universal service.[6] It is readily apparent that support provided by the Universal Service Funds has a very specific purpose and must be used for that purpose or that support can – and will -- be withheld by the USAC administrators in the future.

For purposes of administering USF support in the United States Virgin Islands, Innovative Telephone Company is recognized as an eligible telecommunications carrier and is the designated recipient of all USF support provided to the territory. Representations made by Innovative Telephone Company to the Virgin Islands Public Service Commission and the Federal Communications Commission have shown the territory to be a high-cost service area and, therefore, to merit financial support from the fund administrator – the Universal Service Administrative Company ("USAC")

b. High-Cost Support Mechanism

The FCC mandates that all telecommunications carriers which satisfy the requirements of 47 C.F.R § 54 703 contribute a portion of their receipts to support the Universal Service Fund. As noted earlier in this report, the Universal Service Fund provides for a series of specialized telecommunications-dependent initiatives – rural healthcare, schools and libraries, available and affordable local exchange telephone services – to name the principle ones.

For purposes of this examination, the subject of discussion is limited to the high-cost support mechanism provided for by the Universal Service Fund. As indicated above the designated administrator of the high-cost support mechanism on behalf of the FCC is the Universal Service Administrative Corporation. USAC serves as both the custodian for funds submitted from the carriers and the final determinant of how much of those funds should be provided to support high cost carriers such as Innovative.

After considerable efforts on the part of its staff to ensure USF support is being used for its intended purpose and equitably disbursed amongst eligible candidates, USAC approves release of a lump sum disbursement to the National Exchange Carrier Association ("NECA") – a separate entity that maintains responsibility for financial settlements between

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[5] 47 C F R. 54 101 limits use of universal service support to voice grade access to the public switched network, local usage, DTMF, single party service, emergency services, operator services, inter-exchange services, directory assistance and toll limitation for qualifying low-income customers

[6] 47 C F R 54 7 expressly states that a "carrier that receives federal universal support shall use that support only for the provision, maintenance, and upgrading of facilities and services for which the support is intended "

carriers NECA in turn makes individual disbursements to the eligible companies identified by USAC.[7]

Universal Service Fund Certification Process

a. Filing Requirements

In order for a local exchange carrier to be deemed eligible to receive support from the high-cost pool of funds, an applicant must already be designated by its state regulatory body as an Eligible Telecommunications Carrier ("ETC") in accordance with provisions contained in 47 U.S.C § 214.[8] If a state regulatory agency concludes that it lacks jurisdiction to make such determination the carrier may subsequently apply to the FCC for consideration and approval without prejudice.

All ETCs receiving support from the high-cost fund must submit an annual filing with their respective state regulatory agency attesting to the fact that they intend to use the USF support earmarked for their company in a manner consistent with the designated purposes of the Act.[9] In turn, state regulatory agencies are required to apprise the FCC that they have reviewed the representations made by the local exchange carriers to the FCC pertaining to USF support and concur in their accuracy. This process is generally referred to as the annual certification process

The FCC requires that a formal submission be made each year by October 1 in the form of a letter from a state – or territorial -- regulatory agency.[10] The submission must attest that financial support provided by the Universal Service Fund is being used as intended by the statute's expressed provisions.[11] Beyond that simple requirement the instructions afford a regulatory agency little perspective on how it is to make such a determination

The Virgin Islands Public Service Commission ("VIPSC" or "PSC") has filed a submission with the FCC and USAC for each of the annual reporting periods since the filing requirement was introduced. In constructing the PSC's submission, it has been general practice to solicit such financial and operational information from Innovative Telephone Company ("Innovative" or "Vitelco") that the PSC believed may be useful in establishing the level of compliance by the company with the requirements of 47 U.S.C. § 254(e).[12]

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[7] A recent change provides for eligible companies to request payment directly from USAC rather than from NECA This change represents a procedural change only Eligibility requirements and the level of support provided to an eligible carrier remain unchanged.

[8] See 47 U S C § 214(e)

[9] 47 U S C § 254(e) expressly states that "a carrier that receives such support shall use that support only for the provision, maintenance and upgrading of facilities and services for which the support is intended "

[10] See 47 CFR 54 314 This requirement was most recently reaffirmed in the *Order on Remand, Further Notice of Proposed Rulemaking, and Memorandum Opinion and Order,* CC Docket No 96-45, FCC 03-249, at ¶ 91, released on October 27, 2003 The October 1 submission is made to both the Federal Communications Commission and the Universal Service Administrative Company

[11] A detailed description of the specific information currently required by USAC and the FCC in the submission can be found at www universalservice org/hc

[12] A review of materials provided by Innovative to the VIPSC related to the 2001, 2002 and 2003 submissions were considered sufficient for the needs of the PSC and evidenced no factual errors

On August 1, 2004 Innovative Telephone Company submitted documentation in support of the 2004 certification submission then being prepared by the Virgin Islands Public Service Commission. Upon reviewing the material provided by Innovative, the PSC concluded that some additional examination of universal service support provided the U. S. Virgin Islands may be warranted prior to filing its attestation statement at the end of September. Accordingly, the VIPSC directed that a broader – and more rigorous -- examination be undertaken of universal service support afforded to the United States Virgin Islands and Innovative Telephone Company.

b. Review Process

On May 23, 2001, the Federal Communications Commission (hereafter referred to as the "FCC") revised its universal service rules for eligible telecommunications carriers serving rural and/or insular regions of the United States. By definition contained in 47 U.S.C. § 153(37) Innovative Telephone is a rural telephone company and as such is obligated to pursue policies and programs that are consistent with 47 U.S.C. § 254(b)(3).[13] In pursuit of those goals Innovative Telephone has periodically requested financial assistance from the high-cost universal service fund for the purpose of "provisioning, maintaining and upgrading of facilities and services" that comprise its telecommunications network [14]

To be certain that financial support provided by the universal service fund is employed in a manner consistent with the intent expressed by Congress in 47 U.S.C. § 254(b)(3) state regulatory agencies must file an annual certification with the Universal Service Fund Administrator (hereafter referred to as the "USAC Administrator") and the FCC that all federal high-cost support provided to eligible telecommunications carriers within the state will be used in the prior year in a manner consistent with the Act's requirements.[15] The FCC treats October 1 of each year as the filing deadline for all certification statements by state regulatory agencies filed on behalf of eligible carriers seeking support afforded by 47CFR54.301, 47CFR54 305, and/or 47CFR54.307 and/or 47CFR36, subpart F.[16]

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[13] Section 254(b)(3) provides that "[c]onsumers in all regions of the Nation, including low-income consumers and those in rural, insular, and high cost areas, should have access to telecommunications and information services, including interexchange services and advanced telecommunications and information services, that are reasonably comparable to those services provided in urban areas and that are available at rates that are reasonably comparable to rates charged for similar services in urban areas"

[14] Section 254(e) provides that " only an eligible telecommunications carrier designated under section 214(e) shall be eligible to receive specific Federal universal service support A carrier that receives such support shall use that support only for the provision, maintenance, and upgrading of facilities and services for which the support is intended Any such support should be explicit and sufficient to achieve the purposes of this section This provision is reiterated by the FCC in its rule 47CFR54 7

[15] The rules for such submissions are set forth by the Federal Communications Commission in 47CFR54 314(a) Specifically, certification made pursuant to 47CFR54 314 requires a letter from the appropriate state regulatory authority be filed with both the Office of the Secretary of the Federal Communications Commission clearly referencing CC Docket No 96-45, and with the Administrator of the high-cost universal service support mechanism, on or before October 1 of each year

[16] There is no provision made by the FCC in its rules for any submission made by a state regulatory agency after the October 1 deadline It must, therefore, be assumed that treatment of any submission made after October 1 is at the sole discretion of the FCC and the Administrator of the high-cost support mechanism It cannot be assumed that requests made after October 1 will even be heard – let alone upheld – by the

On August 1, 2004 pursuant to the requirements set forth by Congress in 47 U.S C § 254(e) and 47CFR54.314(d)(1) Innovative Telephone filed its most recent request with the Virgin Islands Public Service Commission seeking universal service fund certification and endorsement. On August 8, 2004 Gorham, Gold, Greenwich & Associates was directed to examine the submissions made by Innovative Telephone in support of its request and render an opinion to the VIPSC of Innovative Telephone's compliance with the requirements of the statute

In preparation for the PSC-mandated review additional support documentation was solicited from Innovative and, subsequently, provided to the review time for examination and authentication. Furthermore, interviews were conducted with individuals responsible for compiling the submitted material to ascertain the accuracy of representations, the reliability of the source material and the relevance of the material to the task before the PSC.

Discussion with members of the VIPSC suggested that the decision to broaden its examination of this year's annual certification filing was predicated on two principal issues –

- the integrity of financial and operational data provided by Innovative to the PSC in its August 1, 2004 filing [consistency]; and

- the confidence that financial support provided by the USF will be used in accordance with the requirements set forth in 47 U.S.C. § 254(e) [compliance]

At the inception of this examination the PSC indicated that the inquiry was being undertaken solely on its initiative and represented the PSC's intention to ensure the public's interest in this matter is fully protected. No evidence -- or suggestion -- of any error or omission in the preliminary filing made by Innovative on August 1, 2004 was indicated by the PSC in its directive to the review team and none should be inferred by any interested party.

i. Consistency

The questions posed by the VIPSC represent two substantively different issues – each requiring an answer independent of any that might afforded to the other. In the first matter, the financial and operational data presented by Innovative in its August 1 submission is, by design, historical performance data. It reflects precise conditions and costs that Innovative has recently experienced in its business operations. The only allowances and/or adjustments made reflect those made for prescribed accounting rules and required reporting methods.

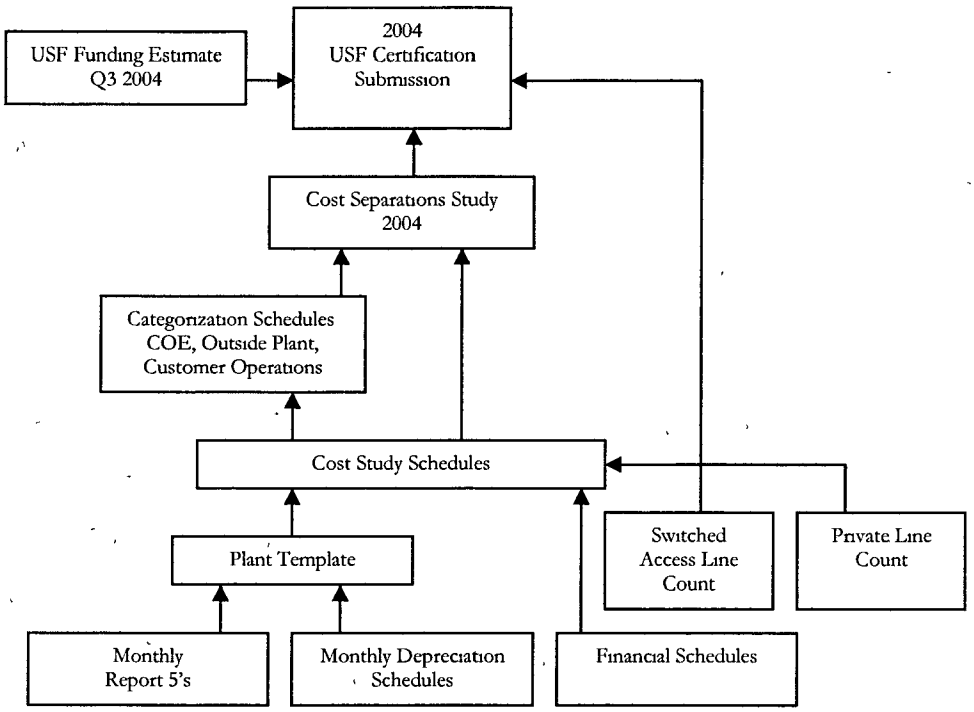
It was concluded by Gorham, Gold, Greenwich & Associates that a forensic verification exercise would be sufficient to address the matter of data integrity; and provide the PSC a comprehensive opinion regarding the probity of the company's 2004 submission.

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responsible parties at the FCC and/or USAC Neither party is under any obligation to consider any submission made after the October 1 deadline See 47CFR54.314(d)(1)

It bears mentions that verification exercises do not generate independent representations to those made by Innovative in its August 1, 2004 filing with the VIPSC Instead, they serve to verify the accuracy of the reported information, the reliability of the source material that supports the reported information and the relevance of that information to the conclusions that must be reached by the PSC under 47 U.S C. § 254(e).

Verification exercises serve to substantiate and validate the individual components of the submission by using standardized comparative analysis techniques. The verification exercises employed in this examination comprised a series of sequential tasks designed to establish clear provenance for each data element presented to the PSC in the August 1 filing. It was decided that for this examination all information shown must be traceable to known -- and available -- source data in order to be deemed reliable, accurate and acceptable.



The illustration above serves as a basic representation of the foundation upon which Innovative's August 1 filing was constructed. The illustration clearly demonstrates that the August 1, 2004 submission made by Innovative uses data extracted directly from various schedules, reports and tables maintained by the company in the course of its other business. In each of those instances, the source represents a filing or report that is a) constructed in accordance with a set of prescribed rules and requirements, b) subject to periodic audit or review for compliance with those rules and c) readily available to the VIPSC, the FCC and the USAC. None of the representations contained in the August 1 submission differ from information reported in the source documents identified above and reviewed in the course of our examination.

It is our opinion after reviewing Innovative's August 1 submission that the financial and operational data included by Innovative in its support documentation is accurate and consistently represented throughout the company's various reporting systems. Furthermore, it is our opinion that the information contained within the August 1 submission is consistent with information reported separately to the FCC and the USAC.

ii. Compliance

In the second matter, the PSC has expressed concern for how support provided by the Universal Service Fund is to be expended by Innovative. In contrast to the first issue the question of intent addresses the future rather than the past -- and there is no certainty that the future will unfold precisely as we might envision it. Therefore, there is less confidence in any conclusion that might be provided in matters regarding the future.

With that said, it must be remembered that the principal compliance standard to which Innovative Telephone must be held responsible remains 47 U.S.C. § 254(e) Specifically, 47 U.S.C. § 254(e) requires that universal service funds be used for a) provisioning, b) maintenance or c) upgrading plant facilities The three categorical references afford beneficiaries some discretion as to how support from the Universal Service Fund can be used – and must be reported. This discretion ranges from whether to use the support to offset operating expenses or reduce borrowing requirements for planned capital investments to how use of universal service funds are accounted for in corporate books and records

Congress effectively entrusted responsibility for how universal service support is to be used with management in the apparent belief that management possessed the necessary skills to identify the most pressing needs and the most appropriate solutions. By forgoing more prescriptive measures Congress appeared to be confident that the beneficiaries of these funds would use them in a manner that is consistent with their intended purposes. It is a generally recognized fact that Congress had both the opportunity and the authority to impose greater strictures than those included in 47 U.S C. § 254(e). The fact that it did not can only be presumed to mean that it believed additional instructions were unnecessary to ensure its intent is met.

The same rationale can be applied to the matter of reporting requirements. Congress prescribed no specific reporting requirement -- or special accounting treatment -- for universal service funds beyond the annual certification process in which we are engaged. It appears that Congress believed the general oversight and safeguards employed by the FCC and USAC are sufficient to the need and additional obligations are unnecessary at this time

The absence of any specific reporting requirement -- or special accounting treatment -- for universal service funds makes the job of gauging compliance with the intent of Section 254(e) much more difficult. However disappointing it might be that neither Congress nor the FCC and USAC require a more granular accounting of how universal service support is used it remains possible to perform some rudimentary analysis of the company's financial statements and offer conclusions regarding its compliance with the intent of Congress.

The constructs of Section 254(e) provide a basic framework in which historical compliance can be gauged even if it cannot adequately measure future intent. By designating three intended purposes for universal support, Congress established an "inferred" perimeter that can be used to examine historical accounting treatment of operating expense and capital investment to determine if universal service funds are fully recognized even if they cannot be distinguished. Although the categorization sets afforded by the statute are relatively broad they offer a common set of categorical standards and a general performance threshold that can be applied to all recipients of universal service funds. Therefore, it is our opinion that using the available framework to judge compliance for Innovative Telephone is fair, reasonable and impartial.

Separately, the support provided by the high-cost universal service fund was fully recognized by Innovative Telephone in the revenue requirement model examined in Docket No. 532. In that proceeding, Innovative Telephone effectively treated support from the high-cost fund as an additional source of revenue thereby relieving subscribers of a portion of the financial obligation associated with that case The net effect was proposed rates that were less than what would otherwise have been required without the high-cost support. Therefore, it is our opinion the treatment accorded universal service support in Innovative's revenue requirement satisfies the intent of 47 U S.C. § 254(e) and demonstrates compliance with its conditions.

In order to form any conclusion regarding Innovative's historical compliance it was necessary to review income statements, balance sheets, schedules and miscellaneous financial submissions prepared on behalf of the FCC, USAC, NECA, VIPSC, EDC and other interested parties for the past three years. In each instance, it was apparent that the aggregate level of support provided by the Universal Service Fund can be fully accounted for by the expenditure levels in one or more of the designated categories provided for in 47 U S.C. § 254(e). We found no incident where the monetary value of high-cost support provided by the Universal Service Fund exceeded the expenditure levels of Innovative Telephone Company for the same accounting period. Therefore, it is our opinion that there is no reason to assume that financial support designated for Innovative Telephone Company in 2004 will be used for any purpose other than that prescribed by 47 U.S C. § 254(e).

Summary of Analysis

(a) Universal Service Cost Determination

Innovative included as part of its August 1, 2004 submission a cost of service calculation indicating its monthly cost of $64.62 per access line.[17] This information corresponds to information submitted separately to the FCC and maintained on-file with the designated administrative organizations. This calculation was made in accordance with requirements set forth in 47CFR54.301(b) of the FCC's rules and regulations. All cost elements contained in the August 1, 2004 submission are cross-referenced and fully sourced for verification The information contained in the submission is further supported by Innovative's 2003 Annual Cost Study prepared separately in accord with the FCC's Part 36 rules. Other financial and operational data contained in the submission is attributed to

[17] Line II B. of Exhibit 1 attached to Innovative USF Request, August 1, 2004

various company books and records, reports and other representations made before the Virgin Islands Public Service Commission or responsible agencies such as the Universal Service Administrative Corporation.

Innovative asserts that the monthly cost to provide universal service in the United States Virgin Islands equates to $4,503,625. This figure represents the jurisdictionally separated costs of Innovative Telephone for the calendar year 2003 Non-universal service related activities are excluded from the cost calculation in accordance with FCC rules In order to derive the monthly per access line figure referenced in paragraph one of this section it is necessary to divide the total monthly cost of providing universal service ($4,503,625) by the number of switched access lines served by Innovative (69,698) Independently performing the necessary calculations confirms that the monthly cost per access line is $64 62 as submitted by Innovative.

(b) Revenue Shortfall Analysis

In its August 1, 2004 submission Innovative indicated the current tariffed rate for residential basic exchange service to be $21.65.[18] As demonstrated in Sub-section (a) above the monthly cost of providing universal basic local exchange service is $64.62 per switched access line. The difference between the revenue generated by current tariff ($21.65) and the cost of provisioning such service ($64 62) is calculated to be $42 97.[19] The difference between revenue generated by current tariffs and the cost of provisioning such service is generally referred to as the revenue shortfall.

(c) High Cost Funding Impact

Innovative submits in its filing that it has a total of 69,698 switched access lines – of which 47,675 residential lines are eligible for support from the federal high-cost fund In sub-sections (a) and (b) above it has been established that the monthly cost to provide universal service exceeds the effective monthly tariff rate by $42.97 per switched access line. By extrapolating the monthly shortfall per line ($42 97) to the number of switched access lines that are eligible for support (47,675) it produces a total monthly revenue shortfall for basic residential local exchange service of $2,048,417. Separately, the Company used the Third Quarter Report of the Universal Service Administrative Corporation to establish a projected monthly high cost support figure of $1,012,447. The monthly difference between the shortfall in cost to provide basic residential local exchange service in the Virgin Islands ($2,048,417) and the funding allowance provided by USAC ($1,012,447) presents a monthly revenue shortfall of $1,035,970 that is unsupported by the federal High-Cost Fund.

Conclusions

This examination constitutes the most extensive evaluation of an annual USF certification filing made by Innovative Telephone Company to the Virgin Islands Public Service Commission to date. In the course of our examination several observations merit mention that have some bearing on our conclusions. Specifically,

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[18] Local Tariff, Section IV

[19] Line III C of Exhibit 1 attached to Innovative USF Request, August 1, 2004

- the level of funding support available to an eligible telecommunications carrier from the high-cost fund is solely determined by USAC and is based on information compiled in accordance with USAC rules
- the level of funding support available to an eligible telecommunications carrier from the high-cost fund is determined by the size of the fund "pool" and the universe of eligible applicants
- universal service support compliance audits are the joint responsibility of the USAC and FCC
- universal service support compliance audits are regularly conducted by USAC auditors "for cause" and at random
- USAC actively monitor the financial and operational conditions of USF recipients to ensure compliance
- the level of support afforded by the universal service fund is insufficient to reduce the identified revenue deficiency

In summary, the high-cost universal service fund is an extremely sophisticated support system that provides state regulators an additional means of ensuring affordable local exchange telephone service. The principal responsibility for determining benefit levels and ensuring compliance rests with USAC. However, the beneficiary controls how funds are recognized and used. It is, therefore, important that funds be used to the purpose for which they are intended. The annual certification process represents a mechanism by which the designated beneficiaries must show that they have fully recognized the level of financial support provided by the high-cost fund. Requiring state regulators to review the annual certification submission USAC serves to ensure the legislative intent of the 104th Congress is fully satisfied.

In the course of our review we are have concluded that Innovative's certification submission is complete and accurate. Furthermore, we have concluded that financial support provided by the high-cost fund is being committed by Innovative in a manner that is consistent with the intent of 47 U.S.C. § 254(e) and to the benefit of the consumers of the Virgin Islands We recommend the VIPSC approve support for Innovative Telephone's pending request for certification.

Based upon a review of the materials submitted by Innovative on August 1, 2004, as supplemented, and discussions with representatives of Innovative Telephone , we are satisfied that Innovative is a qualified eligible telecommunications carrier. Furthermore, it is evident from a review of the submissions made in this proceeding that the company has used its federal universal service support only for the provision, maintenance and upgrade of facilities and services for which support is intended by Section 254(e) of the Communications Act of 1996. Further indication of that fact is that annual operating expenses of $12,531,640 are not supported by the federal high cost fund and must be borne by Innovative through other means. It is the opinion of Gorham, Gold, Greenwich & Associates that Innovative is in full compliance with the requirements set forth by the various federal statutes and rules governing monetary support available from the federal universal service fund At this time we commend the submission made by Innovative to the VIPSC for consideration and recommend that the Commission reaffirm its' designation as

an eligible telecommunications carrier ("ETC") and certify that it has satisfied all of the requirements set forth in Section 47 U S.C. § 254(e)

Issues for Further Consideration

In the course of this examination it became apparent that the Universal Service Fund is currently undergoing serious re-evaluation at the federal level The effort is triggered by events largely related to general economic conditions and structural changes in the telecommunications industry. However, it is clear that the level of universal service support designated for the Virgin Islands may be dramatically affected in the future by these forces It is not unreasonable to assume the support from the Universal Service Fund will decline in the relatively near future as pressures to re-examine both funding and disbursement mechanisms build[20]. The effect of these converging forces will be a pervasive – and most likely permanent -- decline in financial support for the Virgin Islands and the need to examine alternative means of preserving universal service.

Secondly, it has been suggested that additional authorization and reporting requirements may be beneficial to ensuring financial support from the universal service fund is directed at areas of concern It is evident from our review that support provided by the high-cost fund is currently being used in a manner that comports with the requirements set forth in the enabling statute and the rules set forth by the FCC and USAC. However, that does not necessarily mean the funds are committed in a manner that fully addresses the concerns expressed by the PSC in this matter.

Congress provided for the possibility that state regulatory agencies would not feel the level of funding provided by universal service to be adequate to meet all of a community's needs in the near-term. 47 U.S.C § 254(f) affords state regulators a very narrow range of discretionary authority where a state regulatory agency believes additional measures are needed and necessary and are not inconsistent with the Commission's rules.[21] Any proposed action by a state regulatory agency must be promulgated in the form of a regulation (rather than an order) and must not present an additional burden to the universal service fund [22]

The consequent effect of this is that if the PSC deems it necessary to impose additional duties and obligations on Innovative Telephone it has the authority to do so under 47 U.S C. § 254(f). However, to exercise the authority provided by that statute will be extremely difficult.

It is our opinion that the PSC has sufficient authority under Virgin Islands Statutes to achieve the same results without resorting to a relatively cumbersome federal statute.[23] Furthermore, the scope of interest can be significantly broader if the PSC's authority is based

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[20] It bears mention that the estimated level of support from the high-cost fund that Innovative showed in their revenue requirements model for Docket No. 532 was substantially higher than is currently being calculated The difference is a function of lower than anticipated carrier contributions, a larger number of participants and a decline in eligible access lines served by Innovative

[21] 47 U S C § 254(f) provides a stringent set of qualifications and limitations on that authority

[22] Id

[23] See V I CODE ANN TIT 30 §§ 20, 23

on territorial statutes. Regulations promulgated pursuant to 47 U.S.C. § 254(f) are limited to only those services supported by the universal service support fund and may fail to address more significant areas of concern. Any effort by the PSC to exercise its authority under VI statutes requires normal due process consideration before any action can be taken.

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.
ECONOMIC AND MANAGEMENT CONSULTANTS

December 2, 2004

RECEIVED
DEC - 3 2004
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

Illona A Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
12th Floor
State Capitol
Bismarck, ND 58505-0480

Dear Ms. Jeffcoat-Sacco:

Enclosed herewith are the original and five copies of the proposal of Snavely King Majoros O'Connor & Lee, Inc. to provide expert witness consulting services to your Commission in connection with Case No. PU-04-578, the application of Northern States Power Company for an increase in gas distribution rates.

This proposal is submitted in response to your Request for Proposals, dated November 18, 2004

I believe our proposal is fully responsive to your request However, if you or your staff have any questions or comments, please feel free to contact me at (202)371-9156 or by e-mail at charlieking@snavely-king.com.

Thank you very much for this opportunity to submit our proposal

Sincerely,

Charles W King
President

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Cover letter re Proposal
by Snavely King Majoros O'Connor & Lee Inc
12/03/2004 CC Comm Legal FILED (4) Fax

1220 L STREET, NW • SUITE 410 • WASHINGTON, DC 20005
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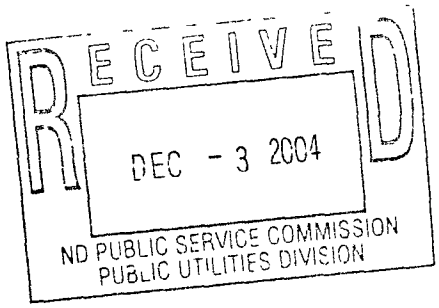
Proposal of

SNAVELY KING MAJOROS O'CONNOR & LEE, INC.

To the North Dakota Public Service Commission

Case No. PU-04-578
Application of Northern State Power Company
For an Increase in Gas Distribution Rates

December 6, 2004



ORIGINAL

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16 PU-04-578 Pages 42
Proposal
by Snavely King Majoros O'Connor & Lee Inc
12/03/2004 CC Comm Legal PUD (4) Mike

Proposal by
SNAVELY KING MAJOROS O'CONNOR & LEE, INC
to the
Public Service Commission of North Dakota
Case No. PU-399-03-296

Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King") is pleased to offer the following proposal to the Public Utilities Commission of North Dakota ("PSC") to provide expert witness consulting assistance in connection with Case No PU-04-578, involving Northern States Power Company's ("NSP") rates for gas distribution service.

I. The Firm

Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 34-year history, members of the firm have participated in over 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

II. Objective

The objective of the work contemplated in this proposal is to develop the Commission Staff's position on four issues pertaining to NSP's request for an increase in its gas rates. (1) the appropriate rate base, (2) the appropriate cost of capital, (3), the appropriate regulated net income, and (4) the appropriate rate design.

III. Issues

A. Rate Base

In 1995, the North Dakota legislature enacted legislation that offered utilities a choice as to test years:[1]

A public utility, at its option, may use any one of the following twelve-month periods as its test year for rate filings with the commission:

> a. A historical test year, which may be either the latest twelve-month period for which actual data is available at the time of filing new schedules or the latest calendar or fiscal year for which actual data is available at the time of filing new schedules.
>
> b. A current test year, which is any consecutive twelve-month period ending not later than twelve months after the date new schedules are filed A public utility selecting a current test year also shall file data for the twelve-month period immediately preceding the current test year selected and that period is the "historical period" for the public utility.
>
> c A future test year, which is any consecutive twelve-month period ending no later than twenty-four months after the date new schedules are filed. A public utility selecting a future test year must file data for the twelve consecutive months immediately preceding the future test year and that period is the "current period" for the public utility

We have not had the opportunity to examine NSP's filing in this case, but we suspect that the Company has filed for a forecast test year, either calendar year ending December 31, 2005 or a "pipeline year" ending August 31 of 2005 or 2006. If NSP does use a forecast year, it must compare that year's results with those of the most recent corresponding historical period. It must demonstrate that its forecasts are reasonable and reliable and that all forecasting assumptions are reasonable, identified, evaluated and justified. These standards apply to both the forecast of the rate base and the forecasted net income.

[1] ¶49 05 04 1

Review of the last two NSP gas rate cases (Case Nos. PU-400-00-521 and PU-400-95-559) indicates that there are likely to controversies associated with the following components of the rate base:

- The level of working capital,
- The level of projected deferred income taxes,
- The treatment of the ratepayer contributions to pension and other post employment benefits, and possibly
- The inclusion of the unamortized portion of the Manufactured Gas Plant cleanup costs in Grand Forks.

Other rate base issues that may arise could include the appropriate level of contributions in aid of construction, the reliability of forecast construction, and the matching of forecast construction with forecast depreciation accruals.

Snavely King is familiar with these issues, having participated in the three most recent Montana-Dakota gas cases and in the most recent NSP electric and gas cases.

B. Cost of Capital

NSP is a wholly owned subsidiary of Xcel Energy, which was created by the merger of Northern States Power Company and New Century Energies, Inc. on August 18, 2000. Since Xcel Energy engages in unregulated activities and in electric service, both of which are subject to far more business risk than gas distribution, it is important that the cost of capital reflect NSP's gas distribution service exclusively, untainted by the activities of affiliated enterprises. This focus is made difficult by the fact that most of the capital used in the Company's gas business is in fact raised by the parent, Xcel Energy As a consequence, Xcel's capital costs may be a poor measure of the actual cost of capital of Xcel's gas distribution activities.

This problem begins with the capital structure. Xcel Energy does not design its capital structure to reflect the business risk of its gas distribution activities A pure gas distribution company can afford far more leverage without adverse debt rating

consequences than can an energy conglomerate such as Xcel For this reason, it may be necessary to impute a debt-equity ratio that more accurately reflects the business risk and the bond ratings that are experienced by "pure" gas distribution companies.

Aside from the capital structure, the other two components of the costs of capital are the cost of debt and the cost of equity. Presumably, NSP has already provided the Commission with its version of the appropriate analytical procedures, the relevant comparable companies, and the correct financial records from which to develop its debt and equity costs. Snavely King proposes to use that presentation as the starting point for its development of NSP's capital cost.

There are two advantages to this approach. The first is that it can minimize the areas of controversy. For example, there is usually little controversy as to the cost of debt. This is an embedded cost that is easily calculable from the records of the company. It may be relevant to exclude debt that was clearly used to finance unregulated ventures, but in general it should be possible to draw the debt cost directly from the Company's presentation.

Even with respect to the much more controversial issue of the cost of equity, it may be possible to sidestep some issues The selection of comparable companies, for example, is always a controversial matter. The Company-sponsored list will most likely be usable, but it may be necessary to exclude some companies as not comparable for a variety of reasons, or add additional companies that better serve as a proxy for NSP's gas operations.

The second advantage flows from the first It is that acceptance of portions of the utility's rate of return evidence can avoid a considerable amount of research By using the utility's data and source documents, the Commission Staff is able to obtain support for a portion of the case with virtually no incremental effort.

Fortunately, the truly controversial issues require relatively little research because they relate more to theory and approach than to data and depth of research. There are a series of artifices that most utility cost of capital witnesses employ to inflate their rate of return conclusions. These include:

Use of unregulated companies as "comparable" to the utility,

Use of the historical risk premium approach;

Use of the Capital Asset Pricing Model as a test of absolute, rather than relative equity return;

Quarterly compounding of dividends in computing the dividend yield portion of the DCF formula;

Inclusion of an allowance for flotation costs;

Selective use of analysts' forecasts; and recently

Use of market rather than book capitalization of equity in the capital structure.

All of these devices have been used in cost-of-capital cases in which Snavely King's professionals have participated As a consequence, Snavely King has developed rebuttal arguments for virtually all of them. Those rebuttal arguments have consistently been accepted by the regulatory commissions.

C. Net Income

As noted, North Dakota law allows a utility to select among three alternative types of test year, and it is likely that NSP has used a forecast test year to support its application. The Company must show that its forecasting assumptions are reasonable, identifiable, evaluated and justified. Typically, utilities use their budgets on the presumption that the budgets are developed without regard to the prospects for a rate increase. This presumption should be challenged by comparing the predicted changes in revenues and expense with the patterns of change during the most recent years. NSP should be required to explain fully any departures from these recent past trends.

Of considerable concern in recent North Dakota cases have been the dramatic increases in the salaries and benefits of executive employees These increases have far exceeded those awarded to hourly and non-management salaried employees, and they to some extent have reflected the overall profitability of the company While the Commission can have no objection to executive increases based on the improved productivity performance of the Company's capital and labor, it should question bonuses, salary increases and benefit enhancements that reflect profitability derived from rate increases. To allow such increases makes the regulatory process somewhat circular. A rate increase creates executive compensation that in turn justifies further rate increases.

A similar problem relates to "institutional advertising" which is designed to enhance the image of the Company. Such image advertising is disingenuous when it is funded by ratepayers. It is not the Company that is promoting its image. Rather, it is ratepayers who are funding the Company's own self-promotion Not only is this type of advertising inappropriate as part of the revenue requirement, it may be in conflict with North Dakota statutes.

D. Cost Allocation and Rate Design

The RFP indicates that NSP is proposing to increase overall revenues by 1.8 percent, but residential gas rates by 4.6 percent. This disproportionate increase to residential customers is no doubt supported by a class cost of service study the purports to show residential customers generating rates of return substantially below those of the other classes. Snavely King is familiar with such cost of service studies and is prepared to refashion them so as to impose less of the load of fixed distribution system costs on residential customers.

Even if the adjusted cost of service study still shows residential customers earning less than the average rate of return, most commissions, including this one, regard highly disproportionate class increases as unfair and unreasonable For example, few commissions would tolerate a substantial rate increase to the residential class while

another class receives a rate reduction. Most commissions require that all classes receive at least a portion of the rate increase, and this is what Snavely King will advocate in this case.

IV. Staffing

Charles W King, President of Snavely King, will be the overall project director. He will also serve as the expert witness on cost of capital and rate design. Michael J. Majoros, Jr., Vice President, will direct the review of NSP's accounting presentation and will provide expert witness testimony on the revenue requirement. Mr. King has testified on behalf of the Adversary Staff in five recent Montana-Dakota Utilities rate cases and the most recent NSP gas rate case. Mr. Majoros testified in Case No. PU-399-03-296, MDU's electric rate case These two principals will be assisted by Snavely King's support staff, consisting of Margaret Kenney, David Geissler, David Dittemore, Kim Hillenbrand, Edgar Bañuelos, Trenise Queen and Mark Sam. Resumes of all of these individuals are attached to this proposal. Also attached are lists of expert witness appearances by Messrs. King and Majoros.

V. Work Product

We have not included examples of past testimonies, as requested in the RFP, because the PSC already has in its possession the testimonies of Charles W. King and Michael Majoros, Jr. in the following cases:

- PU-400-00-521 Northern States Power Gas Rates
- PU-399-01-786 Montana-Dakota Utilities Electric Rates
- PU-399-02-183 Montana-Dakota Utilities Gas Rates and Depreciation
- PU-399-03-296 Montana-Dakota Utilities Electric Rates
- PU-04-97 Montana-Dakota Utilities Gas Rates

However, we would be happy to supply additional testimonies in other jurisdictions if the PSC Staff should so request.

VI. Work Plan

The work tasks required for this project are those conventionally associated with rate cases, as follows:

- Review the Company's initial filing,
- Prepare initial data requests,
- Evaluate the responses to the data requests and determine the availability of data to support the analysis of the issues,
- Evaluate and analyze each issue, quantitatively wherever possible,
- Prepare direct testimony,
- Respond to data requests on the prefiled testimony,
- Review and evaluate the Company's rebuttal testimony,
- Participate in settlement discussions
- Prepare oral surrebuttal testimony,
- Attend hearing in Bismarck, and
- Assist counsel on brief.

Our experience in North Dakota is that oral surrebuttal is typically presented at the hearing. The work hour budget allows two days for the hearing, although it is possible that the hearing will not require two days' attendance by both Snavely King witnesses

The attached schedule sets forth the estimated work hours of company principals and support staff for each task. Total effort is 375 hours, or which more than half represents the time of the Company Principals, Charles W. King and Michael J. Majoros, Jr.

VII. Budget

The attached schedule presents the fee and expense budget by employee category and by the three major subject areas, (1) revenue requirements, which includes both rate

base and net income, (2) cost of capital, and (3) cost allocation/rate design. Footnote 1 explains that the "Staff" category reflects both Senior Consultants (David Geissler and Margaret Kenney) and Junior Consultants (Kim Hillenbrand, Edgar Bañuelos, Trenise Kelly, and Mark Sam). Note that the mix of these categories varies among the three project areas.

The budgets shown under each of the three subject areas are "stand alone" budgets, that is, they reflect the assumption that each topic is assigned alone, without any other topic assignment. For example, both the cost of capital and the cost allocation/rate design budgets show 16 hours attendance at hearings in Bismarck. In fact, if both topics are assigned, Mr. King will appear in Bismarck on both issues, and the cost of his time will be shared between the two project areas.

For this reason, the "Total" workhour and budget column is <u>not</u> the sum of the totals of the three subject areas. The total budget for all three projects reflects the fact that Messrs. King and Majoros will each spend 16 hours attending hearings and four hours in settlement conferences. It also reflects an assumption that the synergy of performing a larger study of essentially all rate case issues will yield a composite savings of 10 percent in professional effort. Finally, it reflects the expenses that will be incurred if all three projects areas are assigned.

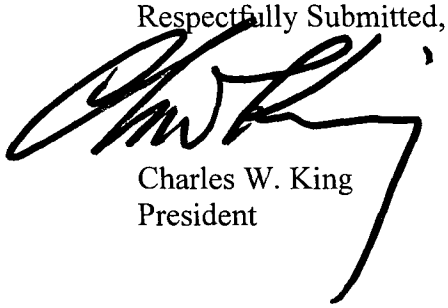
The budget schedule shows total costs of $51,053 for all subject areas. If only revenue requirements were addressed, the budget would be $27,174. If only cost of capital were assigned, the cost would be $16,339. Finally, if only cost allocation/rate design were assigned, the budget would be $16,444.

VIII. Conclusion

We believe the foregoing information responds fully to the Commission Staff's request. However, we would be happy to respond to any questions or comments the Commission Staff may have concerning our firm, its staff or this proposal. Snavely King

appreciates this opportunity to submit its proposal to the North Dakota Public Service Commission.

Respectfully Submitted,



Charles W. King
President

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Snavely King Majoros O'Connor & Lee, Inc.
NSP Gas Rate Case No. PU-04-578
Project Budget

	Task	Workhours									
		Revenue Requirement (Rate Base and Net Income)			Cost of Capital			Cost Allocation/Rate Design			Total All Subjects
		Principals	Staff	Total	Principals	Staff	Total	Principals	Staff	Total	
1	Review Company Filing	8		8	3		3	3		3	14
2	Prepare Initial Data Requests	10		10	5		5	2		2	17
3	Evaluate Responses/Data Availability	8		8	6		6	3		3	17
4	Conduct Evaluation/Analyses	40	35	75	15	15	30	15	40	55	160
5	Prepare Direct Testimony	35	15	50	24	10	34	20	10	30	114
6	Respond to Data Requests	8		8	5		5	3		3	16
7	Review/Evaluate Rebuttal	10		10	8		8	3		3	21
8	Participate in Settlement Discussions	4		4	4		4	4		4	8
9	Prepare Oral Surrebuttal	5		5	1		1	1		1	7
10	Attend Hearing	16		16	16		16	16		16	48
11	Assist Counsel on Brief	9		9	7		7	6		6	22
	Total Workhours	153	50	203	94	25	119	76	50	126	448
	Rate Per Hour (Note 1)	$ 140	$ 85		$ 140	$ 75		$ 140	$ 90		
	Fees (Note 2)	$ 21,420	$ 4,250	**$ 25,670**	$ 13,160	$ 1,875	**$ 15,035**	$ 10,640	$ 4,500	**$ 15,140**	**$ 48,245**
	Expenses										
	Air Fare	900			900			900			1800
	Hotel & Meals	240			240			240			480
	Local Travel	90			90			90			90
	Airport Parking	24			24			24			48
	Reproduction	100			50			75			150
	Delivery and Postage	150			150			150			200
	Total Expenses			1,504			1,304			1,304	2,808
	Total Costs			**$ 27,174**			**$ 16,339**			**$ 16,444**	**$ 51,053**

Note 1 The billing rates for "Staff" are blends of $100 per hour for David Geissler, David Dittemore and Margaret Kenney and $55 per hour for Kim Hillenbrand, Edgar Banuelos, Trenise Queen and Mark Sam

Representations and Certifications

Equal Opportunity Employer

Snavely King Majoros O'Connor and Lee, Inc. is an equal opportunity employer The racial makeup of the firm's staff is as follows:

3 African-Americans
1 Asian-American
1 Hispanic-American
7 Caucasian-Americans

The gender makeup of its staff is

3 women
9 men

Americans With Disabilities Act:

This will certify that the premises and work practices of Snavely King Majoros O'Connor & Lee, Inc. conform with the Americans with Disabilities Act

Conflict of Interest Disclaimer

Neither Snavely King Majoros O'Connor & Lee, Inc. nor any of its employees have any personal, investment or professional interests that would in any way conflict with their unbiased representation of the Adversary Staff of the North Dakota Public Service Commission in the forthcoming Northern States Power gas rate case, or with any other proceeding before the Commission.

Charles W. King
President
Snavely King Majoros O'Connor & Lee Inc

Charles W. King

Experience

Snavely King Majoros O'Connor & Lee, Inc.
Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics

Mr King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U S Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles Mr King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U S Congress

In telecommunications, Mr King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, earnings and depreciation Mr King recently directed analyses of the prices of services under Federal Government's FTS2000 long distance system

In addition to his appearances as a witness in judicial and administrative proceedings, Mr King has negotiated settlements among private parties and between private parties and regulatory offices Mr King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations

In Canada, Mr King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U S Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development

Principal Consultant (1966-1968)

Mr King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc , Mr King engaged in numerous research efforts relating primarily to economic development and transportation

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr King was responsible for the review of all federal statistical and data-gathering programs relating to transportation

Education

Washington & Lee University, B A in Economics

The George Washington University, M A in Government Economic Policy

CHARLES W. KING
Snavely King Majoros O'Connor & Lee, Inc
1220 L Street, N W., Suite 410
Washington, D.C 20005
(202) 371-1111

Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission	U-1345-I	Arizona Public Service Co	December 16, 1980
	Arizona Retailers Association	U-1345-II	Arizona Public Service Co	January 15, 1981
CA	California Retailers Association	57666	Pacific Gas & Electric Co	March 6, 1978
	California Retailers Association	57602	Southern California Edison	April 25, 1978
	California Retailers Association	59351	Pacific Gas & Electric Co	June 12, 1981
	California Retailers & California Manufacturers	59351	Southern California Edison	May 20, 1982
	California Retailers Association	61138	Southern California Edison	May 28, 1982
CO	U S Department of Defense	I&S 1100	Colorado Springs (Elec)	June 14, 1977
	J C Penny Company	5693	All Electric Utilities	March 8, 1978
	U S Department of Defense	I&S 1339	Colorado Springs DPU (Gas)	October 18, 1979
	U S Department of Defense	I&S 1540	Colorado Springs DPU (Gas)	February 9, 1982
	U S Department of Defense	C Council	Colorado Springs DPU (Gas)	September 30, 1984
	U S Department of Defense	C Council	Colorado Springs DPU (Elec)	June 6, 1985
	U S Department of Defense	C Council	Colorado Springs DPU (Elec)	May 19, 1986
	U S Department of Defense	C Council	Colorado Springs DPU (Elec)	June 30, 1987
CT	Retailers Merchants Association	72-0204	Various Electric Utilities	July 22, 1976
	Division of Consumer Counsel	76-0604,5	CL&P and HELCO	November 10, 1977
	Public Utilities Control Auto	78-0303	Bridgeport Hydraulic Co	(none)
	Division of Consumer Counsel	80-0403,4	CL&P and HELCO	August 11, 1980
	Division of Consumer Counsel	81-0413	United Illuminating Company	July 20, 1981
	Division of Consumer Counsel	81-0602,4	CL&P and HELCO	October 5, 1981
	Division of Consumer Counsel	82-0701	CL&P	September 28, 1982
	Coalition of Hotels, Alloys & Retailers	85-10-22	CL&P	(none)
	Coalition of Hotels, Alloys & Retailers	87-07-01	CL&P	April 25, 1988

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
DC	D C People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D C People's Counsel	715	Potomac Electric Power Company	(none)
	D C People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D C People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D C People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D C People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D C People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D C People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D C People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D C People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D C People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D C People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D C People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D C People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D C People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D C People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D C People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D C People's Counsel	847	Washington Gas Light Company	June 27, 2001
	D C People's Counsel	989	Washington Gas Light Company	May 22, 2002
	D C People's Counsel	1016	Washington Gas Light Company	September 23, 2003
DE	Delaware PSC Staff	94-164	Artesian Water Company	Filed March 10, 1995
	Delaware PSC Staff	94-149	Wilmington Surburban Water Company	March 10, 1995
	Delaware PSC Staff	04-152	Tideweater Utilities Company	Filed July 26, 2004
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
	Georgia Public Service Commission	14311-U	Atlanta Gas Light Company	April 8, 2002
	Georgia Public Service Commission	17066-U	Georgia Power Company	July 31, 2003
	Georgia Public Service Commission	18300-U	Georgia Power Company	October 26, 2004
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983
IL	Illinois Retail Merchants Association ("IRMA"/ Chicago Bldg Mgrs Association ("CBMA")	76-0698	Commonwealth Edison	June 22, 1977
	IRMA/CBMA	76-0568	All Eletric Utilities	(none)
	IRMA/CBMA	80-0546	Commonwealth Edison	March 5, 1981
	IRMA/CBMA	82-0026	Commonwealth Edison	July 22, 1982
	IRMA/CBMA	83-0537	Commonwealth Edison	March 19, 1984
	IRMA/CBMA	87-0427	Commonwealth Edison	March/April 22, 1988
	IRMA/CBMA	90-0169	Commonwealth Edison	October 29, 1990
	City of O'Fallon, IL	02-0690	Illinois-American Water Company	Filed Feb 5, Apr 11,2003
IN	Indiana Retail Council	35780-S2	N Ind Public Service co	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J C Penny Company	115,379-U	All Kansas Utilities	January 22, 1981
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co	April 25, 1979
	Attorney General of Kentucky	2002-145	Columbia Gas of Kentucky	Filed August 8, 2002
	Attorney General of Kentucky	2003-252	Union Heat Light & Power Co	September 30, 2003
	Attorney General of Kentucky	2004-67	Delta Gas Company	August 18, 2004

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977
	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
	Giant Foods, Inc	8855	Baltimore Gas & Electric Company	January 8, 2003
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
	Michigan Attorney General	U-13380	Consumers Energy Company	September 9, 2002
	Michigan Attorney General	U-13715	Consumers Energy Company	April 24, 2003
	Michigan Attorney General	U-13808	Detroit Edison Company	Dec 12, 2003, Jan 30, Mar 5, March 26, 2004
	Michigan Attorney General	U-12999	Consumers Energy Company	March 10, 2004
	Michigan Attorney General	U-13898,9	Michigan Consolidated Gas Co	August 23, 2004

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-786	Montana-Dakota Utilities (Electric)	February 25, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas)	October 7, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas Depr)	Filed April 7, 2003
	North Dakota Public Service Commission	PU-399-03-296	Montana-Dakota Utilities (Electric)	Filed October 15, 2003
	North Dakota Public Service Commission	PU-04-97	Montant-Dakota Utilities (Gas)	Filed July 6, 2004
NH	Business & Industry Association of N H	79-187-II	Public Service of N H	February 6, 1981
	Business & Industry Association of N H	80-260	Public Service of N H	February 5, 1981
	Business & Industry Association of N H	82-333	Public Service of N H	November 2, 1983
NJ	N J Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N J Natural Gas Company	(none)
	Resorts International Hotel, Inc	8011-827	Atlantic City Sewerage Co	(none)
	Dept of Public Advocate	822-116	Atlantic City Electric Co	August 11, 1982
	Dept of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989

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State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
NY	N Y Council of Retail Merchants	26806	All Electric Utilities	February 3, 1976
	Metropolitan N Y Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N Y Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N Y Metro Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
PA	Pennsylvania Retail Association	76-PRMD-7	All Electric Utilities	September 7, 1977
	Southeastern Pa Transp Authority	R-811626	Philadelphia Electric Company	December 11, 1981
	Eastern Penn Energy Users Group	R-822169	Penn Power & Light Company	March/April 1983
	Eastern Penn Energy Association	R-842651	Penn Power & Light Company	December 3, 1984
	Penn Business Utility User Group	R-850152	Philadelphia Electric Company	February 19, 1986
	Pennsylvania Office of Consumer Advocate	R-00016339	Pennsylvania-American Water Co	September 19, 2001
TX	Houston Retailers Association	5779	Houston Lighting Company	October 19, 1984
	Houston Retailers Association	6765	Houston Lighting Company	September 25, 1986
	Cities for Fair Utility Rates	8425/8431	Houston Lighting Company	April 25, 1989
UT	Div Of Public Utilities Dept of Commerce	98-2035-33	Pacific Corp	Filed August 16, Sept 22, 1999
VA	Consumer Congress of Virginia	19426	Virginia Electric Power Company	July 1, 1975
	Consumer Congress of Virginia	19960	Virginia Electric Power Company	September 19, 1978
	Va Business Committee on Energy	PUE 7900012	Virginia Electric Power Company	February 25, 1981
	Virginia Pipe Trades Council	PUE 8900051	Old Dominion Electric Corp &	October 31, 1989
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AL	U S Department of Defense	24472	All Telephone Companies	June 14, 1995
AK	GCI Communications, Inc	U-97-82,U-97-143	Alaska Communications Systems	Filed Feb 25, April 5, 2004
AZ	Arizona Burglar & Fire Alarm Association	9981-E-1051-80-64	Mountain State Telephone	(none)
	Federal Executive Agencies	E-1051-88-146	Mountain State Telephone	(none)
	U S Department of Defense	T-01051B-99-0105	US WEST Communications	Filed July 26, Sept 8, 2000
CA	Western Burglar & Fire Alarm Association	59849	Pacific Telephone & Telegraph	March 25, 1981
	Western Burglar & Fire Alarm Association	5984cont	Pacific Telephone & Telegraph	June 23, 1982
	Western Burglar & Fire Alarm Association	A83-01-22	Pacific Telephone & Telegraph	June 29, 1983
	Western Burglar & Fire Alarm Association	A83-02-02	General Telephone of California	January 17, 1984
	Western Burglar & Fire Alarm Association	A82-11-07	Pacific Telephone & Telegraph	Jan 18, Oct 31, Nov 28, 1984
	Western Burglar & Fire Alarm Association	A85-01-034	Pacific Telephone & Telegraph	June 4, 1985, October 2, 1986
	Western Burglar & Fire Alarm Association	A87-01-02	General Telephone of California	October 22, 1987
	Western Burglar & Fire Alarm Association	A88-07-17019	Pac Bell Tel & GTE of CA	January 23, 1989
	California Cellular Resellers	A 88-11-1040	All Cellular Carriers	August 11, 1989
	Federal Executive Agencies	I 87-11-033	All Telephone Companies	March 6-7, 1991
	California Cellular Resellers	I 88-11-040	All Cellular Carriers	August 19, 1991
	Cellular Services, Inc	I 88-11-040	All Cellular Carriers	October 3, 1991
	Federal Executive Agencies	A92-05-004	Pacific Telephone & Telegraph	June 9, 1993
CO	U S Department of Defense	I&S 717	Mountain Bell Telephone Company	1972
	U S Department of Defense	I&S 1700	Mountain Bell Telephone Company	(none)
	U S Department of Defense	Appl	Mountain Bell Telephone Company	September 18, 1986
	U S Department of Defense	I&S 1766	Mountain Bell Telephone Company	November 28, 1988
	Colorado Municipal League	Appl 36883	Mountain Bell Telephone Company	December 13, 1988
	U S Department of Defense	I&S 891-O82T	U S West Communications	February 21, 1990
	U S Department of Defense	905-544T	U S West Communications	July 17, 1991
	U S Department of Defense	90A-665T	U S West Communications	October 23, 1991
	U S Department of Defense	92M-039T	U S West Communications	February 24-24, 1992
	U S Department of Defense	92S-229T	U S West Communications	July 30-31, 1992
	U S Department of Defense	90A-665T	U S West Communications	November 6, 1996
	AT&T	96S-331T	U S West Communications	April 17, 1997

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co.	November 10, 1977
	CT Cellular Resellers Assn	89-12-05	Southern New England Telephone Co.	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co.	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co.	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co.	December 5, 2000
DC	D C People's Counsel	729	Chesapeake & Potomac Tel Co	May 13, 1980
	D C People's Counsel	798	Chesapeake & Potomac Tel Co	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel Co	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel Co	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel Co	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel Co	October 7, 1993
DE	Public Service Commission	Depr Repre	Diamond State Telephone Co	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co	July 31, 1987
	Public Service Commission	Depr Repre	Diamond State Telephone Co	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
ID	U S Department of Energy U S Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co Mountain Bell Telephone Co	May 16, 1983 March 6, 1984
IL	Illinois Aalarm Companies Attorney Generaal of Illinois GTE Sprint Communications Co Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr Repr 166 856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
KY	Kentucky Cable Telecommunications Assn Kentucky Cable Telecommunications Assn	2000-414 2000-39	Blue Grass Energy Cooperative Cumberlant Valley Electric, Inc	January 11, 2001 January 11, 2001
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co U S Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co	August 5, 1983 (none)

State	Telecommunications Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utility	
MO	GTE Sprint Communications Co	TR83-253	Southwestern Bell Tel Co	September 5, 1983
	Federal Executive Agencies	TC-89-14	Southwestern Bell Tel Co	(none)
	Federal Executive Agencies	TO-89-56	Southwestern Bell Tel Co	November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel Co	May 15, 1990
NJ	Department of Public Advocate	Depr Repr	N J Bell Telephone Company	Mar-79
	Department of Public Advocate	815-458	N J Bell Telephone Company	October 15, 1981
	Department of Public Advocate	Depr Repr	N J Bell Telephone Company	March 1, 1982
	Department of Public Advocate	Depr Repr	N J Bell Telephone Company	February 1, 1985
	Department of Public Advocate	T092030358	N J Bell Telephone Company	September 30, 1992
NM	New Mexico Corporation Commission	1032	Mountain Bell Telephone Co	November 14, 1983
	New Mexico Corporation Commission	86-151-TC	General Telephone of Southwest	February 5, 1987
NV	Prime Cable of Las Vegas	95-8034/8035	Central Telephone - NV	Filed November 22, 1995
	Prime Cable of Las Vegas	96-9035	Sprint/Centel, Nevada Bell	June 2, 1997
NY	Holmes Protection, Inc	27350	New York Telephone Company	October 17, 1978
	Holmes Protection, Inc	27469	New York Telephone Company	May 17, 1979
	5 Alarm Companies	27710	New York Telephone Company	July 24, 1980
	GTE Sprint Communications Co	28425	All Telephone Companies	July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate	Depr Repr	Southern Bell	July 1, 1986
	Office of Consumer Advocate	86-511-C	Southern Bell	December 11, 1986
	Office of Consumer Advocate	86-541-C	General Telephone of South	April 8, 1987
	Office of Consumer Advocate	Depr Repr	Southern Bell	July 10, 1989
	Office of Consumer Advocate	89-180-C	ALLTEL of South Carolina	September 26, 1989

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State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
TX	U S Department of Defense	8585/8218	Southwestern Bell Telephone Co	(none)
VA	U S Dept Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989
VI	V I Department of Commerce V I Public Service Commission	205 341	Virgin Islands Telephone Co Virgin Islands Telephone Co	April 29, 1980 March 20, 1991
WA	U S Department of Defense U S Department of Defense U S Department of Defense U S Department of Defense WA Attorney General/TRACER U S Department of Defense U S Department of Defense WA Attorney General/TRACER WA Attorney General/TRACER U S Department of Defense WA Attorney General/WeBTEC/AARP	U-72-39 U-87-796-T U-88-20524 U-89-2698-F UT-940641 UT-941464 UT-951425 UT-961632 UT-021120 UT-040788	Pacific Northwest Bell Pacific Northwest Bell Pacific Northwest Bell US West Communications US West Communications US West Communications US West Communications US West Communications GTE Northwest, Inc Qwest Communications Verizon Northwest, Inc	1973 December 20, 1983 November 8, 1988 November 28, 1989 Filed October 14, 1994 June 22, 1995 January 22, 1996 Filed June 23, 1997 July 29, 1997 May 22, 2003 August 12, 2004
WI	GTE Sprint Wisconsin Consumers Utility Board Wisconsin Consumers Utility Board	6720-TR-38 2055-TR-102 5846-TR-102	All Telephone Companies CenturyTel of Central Wisconsin Telephone USA, LCC	October 20, 1983 June 26, 2002 June 26, 2002

Client	Docket	Subject	Date of Cross-Examination
Federal Communications Commission			
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeornautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind Data Com Mfg Assn	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et al	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et al	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et al	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va Electric Power Co	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

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Client	Docket	Subject	Date of Cross-Examination
U S Congress			
National Retail Merchants Association National Wireless Resellers Association	House/Senate Hearings House Commerce Committee	Electric Rate Reform Legislation Interconnection & Resale of Wireless Services	1976, 1977 & 1979 October 12, 1995
Federal Maritime Commission			
State of Hawaii Foss Alaska Line Palmetto Shipping and Stevadoring	71-18 79-54 85-20	Ocean Shipping Rates Barge Rate Increase Vessel Charge Liability	October-71 July 1979 October 27, 1986
Interstate Commerce Commission			
Western Coal Traffic League Western Coal Traffic League Western Coal Traffic League Arkansas Power & Light Co Central Illinois Light Co Western Coal Traffic League	Ex Parte 349 Ex Parte 357 Ex Parte 375 (Sub1) 37276 37450 Ex Parte 347	R R Rate Increase R R Rate Increase R R Rate Increase Cost of Capital Cost of Capital Costing Methods	May-76 Oct-78 June 1, 1980 (none) March 10, 1981 (none)
Civil Aeronautics Board			
Thomas Cook, Inc	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			
Surface Transportation Board			
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr Majoros provides consultation specializing in accounting, financial, and management issues He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies Mr Majoros has appeared before Federal and state agencies His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery Mr Majoros has also provided consultation to the U S Department of Justice

Mr Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice He has also developed the firm's capabilities in the management audit area

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems, preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission, accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities Mr Majoros also assisted in an antitrust proceeding involving a major electric utility He submitted expert testimony in FERC Docket No RP79-12 (El Paso Natural Gas Company) In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No RM 80-42

Handling Equipment Sales Company, Inc.
Treasurer (1976-1978)

Mr Majoros' responsibilities included financial management, general accounting and reporting, and income taxes

Ernst & Ernst, *Auditor (1973-1976)*

Mr Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes

University of Baltimore - *(1971-1973)*

Mr Majoros was a full-time student in the School of Business

During this period Mr Majoros worked consistently on a part-time basis in the following positions Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M Carney & Co , CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards

Central Savings Bank, *(1969-1971)*

Mr Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student During his tenure at the bank, Mr Majoros gained experience in each department of the bank In addition, he attended night school at the University of Baltimore

Education

University of Baltimore, School of Business, B S – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C P A s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No RM 80-42, 1980

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991

"Impaired Assets Under SFAS No 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996

"What's 'Sunk' Ain't Stranded Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co
1983	New Jersey 1/	815-458	New Jersey Bell Tel Co
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co
1984	Dist Of Columbia 7/	785	Potomac Electric Power Co
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist Of Columbia 7/	798	C&P Tel Co
1984	Pennsylvania 13/	R-832316	Bell Telephone Co of PA
1984	New Mexico 12/	1032	Mt. States Tel & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel & Telegraph
1984	Colorado 11/	1655	Mt States Tel & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co
1984	Pennsylvania 3/	R842621-R842625	Western Pa Water Co
1985	Maryland 8/	7743	Potomac Electric Power Co
1985	New Jersey 1/	848-856	New Jersey Bell Tel Co.
1985	Maryland 8/	7851	C&P Tel Co
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila Suburban Water Co
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel Co of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co
1986	Maryland 8/	7754	Chesapeake Utilities Corp

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1986	Pennsylvania 3/	R-850268	York Water Co
1986	Maryland 8/	7953	Southern Md Electric Corp
1986	Idaho 9/	U-1002-59	General Tel Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co
1987	Dist Of Columbia 7/	842	Washington Gas Light Co
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel Co
1988	Dist Of Columbia 7/	869	Potomac Electric Power Co
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co
1991	Pennsylvania 3/	P900465	United Tel Co of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co
1991	Pennsylvania 3/	R-911892	Phil Suburban Water Co
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele Co – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co
1993	Georgia 23/	4451-U	Atlanta Gas Light Co
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co
1994	Iowa 6/	RPU-93-9	U S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm Suburban Water Corp
1995	Connecticut 25/	94-10-03	So New England Telephone
1995	Connecticut 25/	95-03-01	So New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa

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1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co
1999	Maryland 8/	8795	Delmarva Power & Light Co
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia

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2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co - Md 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co -W Va 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co
South Carolina 22/	1999-072-E	Carolina Power & Light Co
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D C People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U S Dept of Defense	43/ Nevada Bureau of Consumer Protection
12/ N M State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U S Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm	
24/ Delaware Public Service Comm	
25/ Conn Ofc Of Consumer Counsel	
26/ Arizona Corp Commission	
27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U S General Services Administration	

David R. Geissler

Experience

Snavely King Majoros O'Connor & Lee, Inc.
Washington, DC

Senior Consultant (2001-Present)

Mr Geissler is an information technologies expert, who has developed and implemented telecommunications upgrades, database management systems, and data tracking software.

On behalf of a newly merged manufacturing client, Mr Geissler successfully managed the system design, bid package and bid evaluation process for over 10,000 routes offered to 240 trucking companies Using Microsoft Access, he evaluated almost 500,000 individual bids, supporting various intermodal and truck sizes among 60 plant or distribution locations

Mr Geissler has also assisted in the preparation of expert witness testimony on behalf of the State of Kansas concerning the plans by a regulated telecommunications carrier to outsource its IT functions

UUNET
Contactor (1996-2001)

Mr Geissler successfully upgraded this telecommunications company's invoicing system This involved designing and building the Electronic Data Interface capability, creating the accounting interfaces and automating the invoice management process It also required the merging of data from two data centers

SAIC
McLean, VA
Senior Systems Engineer (1991-1996)

Mr Geissler provided technical and project management support for a variety of projects, including the design of a client server application for an automated tracking system for the Conrail transportation system, the implementation of software for risk assessment for nuclear cleanup of Energy Department sites, and the development of system architecture for integrating the FAA's advanced automated systems

Fairchild Industries
Germantown, MD
System Engineer (1988-1991)

Mr Geissler co-designed and developed a microprocessor-based test bed for low-level integration of small satellite systems on behalf of the Air Force. He developed real-time commercial software for a 1553 data logger/processor and supported ground system telemetry and commanding on a UNIX based microprocessor

SpaceCom/Contel
Gaithersburg, MD
Software Engineer (1985-1988)

Mr Geissler led an effort to design and implement a discrete event simulator for analyzing a multiple satellite communications system

Vitro
Silver Spring, MD
(Engineer 1983-1983)

Mr. Geissler supported the proposal phase of the Advanced Automated System of the Air Traffic Control System

Education
Bachelor of Science in Physics
University of New Hampshire

David Dittemore

Experience

Snavely, King & Associates, Inc.

Senior Consultant (2003 to Present)

Mr Dittemore provides written and oral testimony for clients on a variety of regulatory issues He performs prudence reviews on selected relevant issues as identified from reviews of utility operations Mr Dittemore conducts comprehensive revenue requirement analysis of utilities seeking rate increases He analyzes cost allocations and affiliate transactions for reasonableness and consistency with established costing principles

The Williams Companies

Manager, Regulatory Affairs (2000-2003)

Mr Dittemore monitored and researched development and communications economics He participated in due diligence efforts in targeting investor-owned utilities for full requirements power contracts Mr Dittemore researched key state and federal rules to identify the potential advantages and disadvantages of entering selected markets He worked with the Business Development Group on a number of focused projects to identify potential acquisition targets

Kansas Corporation Commission

Utilities Division Director(1997-1999)

Assistant Division Director (1996-1997)

As Division Director, Mr Dittemore was responsible for manging employees with the goal of providing timely, quality recommendations to the Commissioin covering all aspects of natural gas, telecommunications and electric regulation He responded on behalf of the Commission to legislative inquires as requested, and sponsored expert witness testimony before the Commission and the Kansas legislature on selected regulatory issues Mr Dittemore managed a budget in excess of $2 million, recruited professional staff, and monitored trends, current issues and new legislation relating to all Commission-regulated utility industries He was responsible for negotiating with utilities on major issues pending before the Commission and consulting with attorneys on a daily basis to ensure that the Utilities Division objects were being met

Chief of Accounting (1990-1995)

Mr Dittemore supervised nine employees, provided expert witness testimony on a variety of revenue requirements issues, and coordinated and managed consulting contracts Mr Dittemore was also responsible to hiring and training new employees

Auditor (1984-1990)

Mr Dittemore performed on-site audits and analyses of utility records and accounts, provided expert witness testimony, and assisted in the training to less experienced employees

Missouri Gas Energy

(Senior Rate Manager 1995-1996)

Mr Dittemore was responsible for assembling all necessary data for this company's first-ever rate case filing with the Missouri Public Service Commission This project involved reviewing and responding to hundreds of interrogatories and data requests, training and directing two regulatory analysts, developing a revenue requirements model, and interfacing with regulatory auditors

Amoco Production Company

Accountant (1982-1984)

Mr Diittemore was responsible for revenue reporting and royalty payments for gas liquids at several large processing plants

Education

B S in Accounting, Central Missouri State University, 1982

Certified Public Accountant, 1984
Oklahoma Certificate #7562

Memberships

Cherokee Nation

Margaret Kenney

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

Consultant (1995-Present)
Analyst (1995-Present)
Administrative Assistant (1994-1995)

Ms Kenney provides analytical support to SK clients and senior consultants Her responsibilities include cost modeling, operations simulation, financial analysis and reporting, database management and research She has experience in a variety of projects in the transportation and telecommunications areas

Her transportation projects have included extensive cost and revenue analyses of rail freight movements, along with preparation of databases for use in rate negotiations with the railroads Using a Geographic Information System, Ms Kenney prepares rail system maps for use in negotiations as well as use in statements filed before the Surface Transportation Board These maps depict traffic volumes and flows and various merger scenarios

Her telecommunications and public utility experience includes the preparation of complex regulatory reports for submission to state and federal regulatory agencies Ms Kenney also supports company witnesses and prepares exhibits for use in the depreciation aspects of regulatory proceedings These exhibits range from a comparison of the depreciation reserves for various accounts to the generation of life curves using in-house developed software

As an Administrative Assistant Ms Kenney assisted with the preparation of testimony, exhibits, briefs and other supporting documentation for proceedings before state and federal regulatory bodies Ms Kenney also performed the firm's accounting functions using JURIS and other software systems, and maintained the firm's accounting database Her responsibilities included accounts receivable, accounts payable and payroll

U.S. Air Force, Hickam AFB, HI

Intelligence Quality Control Specialist (1988 to 1991)

Ms Kenney maintained and operated a data base with world wide scope, containing complex and constantly changing intelligence information Calling on this data base and other resources, Ms Kenney was responsible for the accurate and timely dissemination of intelligence reports in support of the U S Commander-in-Chief, Pacific, CINCPACAF, CINCPACFLT, as well as operational units throughout the pacific theater She performed Quality Control for a staff of 10 analysts editing their reports for accuracy and standardization She compiled Top Secret reports and transmitted these reports to users via Autodin, a secure communications network Ms Kenney performed data base updates and catalogued incoming film products She produced statistical data outlining areas requiring training and performed such training Ms Kenney also directed rapid response data base and information system trouble shooting efforts when Imagery Division personnel experienced problems with the Computer-Aided Tactical Information System

U.S. Air Force, Hickam AFB, HI

Imagery Analyst (1988 to 1991)

Accessing large and inter-related data bases, Ms Kenney analyzed imagery from national reconnaissance platforms and prepared imagery intelligence reports for the U S Pacific Command She nominated significant intelligence items for briefing to the HQ PACAF staff Responding to changing requirements, Ms Kenney retrieved target information from national intelligence data bases and updated and maintained in-house target reference material

Education

University of South Florida, Tampa, FL
B S in Business Administration, 1992

Edison Community College, Fort Myers, FL
A A in Business Administration 1991

Community College of the Air Force, Montgomery, AL

A A S in Intelligence and Imagery Analysis 1991

Kim Hillenbrand

Experience

Snavely King Majoros O'Connor & Lee Inc Washington, DC

Analyst, Transportation (2003 to Present)

Mr Hillenbrand provides analytical support to SK clients and senior consultants His responsibilities include cost modeling, operations simulation, financial analysis and reporting, database management and research

Mr Hillenbrand's work has primarily been in SK's Transportation group His projects have included extensive cost and revenue analyses of rail freight movements, along with preparation of databases for use in rate negotiations with railroads Mr Hillenbrand has prepared action plans and presentations for clients including potential merger analyses, plant site locations, and rail service issues Additionally, he conducts research in the chemical, petroleum and transportation industries Mr Hillenbrand has assisted in the preparation of presentations and testimony before the Surface Transportation Board In addition Mr Hillenbrand has assisted in the marketing of SK products to potential clients

Leventhal Seneter & Lerman PLLC, Washington DC

Temporary Legal Assistant (Spring 2003)

Mr Hillenbrand assisted in the migration of Televisa's patent and trademark portfolio from Leventhal Seneter & Lerman to Televisa's in house counsel Mr Hillenbrand managed the distribution of incoming documents including from EEO and FCC filings from clients and assisted in all aspects of LS & L's broadcasting, media, and satellite practices

Skadden, Arps, Slate, Meagher & Flom LLP, Washington DC

Temporary Legal Assistant (2002)

While contracted with Skadden Arps, Mr Hillenbrand assisted in a wide range of legal work Mr Hillenbrand coordinated a 750,000 page document production and privilege log for a Department of Justice antitrust filling for the Northrop Grumman-TRW merger He also compiled and managed privilege logs and prepared document productions on behalf of clients for SEC investigations Mr Hillenbrand conducted first review of client documents for SEC and Congressional investigations

North American Securities Administrators Association (NASAA), Washington DC

Temporary Legal Assistant (Spring 2002)

Mr Hillenbrand assisted in a wide area for projects for NASAA He assisted state security regulators in the first settlement between New York State and Merrill Lynch regarding conflict of interest between there research groups and investment banking groups Mr Hillenbrand conducted verification and complaint checks of stockbrokers and Certified Financial Advisors for investors and answered questions regarding the Series 6 and 63 Exams

Acsys, Inc (2003)
Law Resources (2001-2003)
Washington DC

Mr Hillenbrand provided temporary work for law, financial, and real-estate firms

RVC (formerly Reuters Venture Capital) London, England

Analyst, Intern (2000)

Mr Hillenbrand assisted on a survey of Asia venture capital markets in preparation for future venture capital and fund of fund investments in the region The survey comprised of an analysis of sources of capital, major investors, and destinations of capital in Asia

Education

Connecticut College, 2001

B A Economics
B A International Relations

Georgetown University, Summer 1999

Summer Course Work

Citizenship

United States
United Kingdom

Edgar Bañuelos

Experience

Snavely, King & Associates, Inc.
Washington, DC

Cost Analyst (2003 to Present)

Mr Bañuelos prepares and implements spreadsheet analyses, transportation route and cost modeling and financial analyses for clients and senior executives Clients include Shell, Vulcan, Monsanto, and Chevron

Health Plus
New York, NY

Community Health Associate (2002)

On behalf of the Health Education and Community Outreach Department of Health Plus, Mr Bañuelos conducted educational workshops and bilingual outreach to indigent Health Plus members

Mexican Consulate
New York, NY

Health Project Researcher/Organizer (2001-2002)

Mr Bañuelos designed and executed rights and obligations contracts between the Consulate and health plan providers, hospitals, community-based organizations (CBOs), educational and legal services He established over 50 committed contacts for an online directory of 100 of the most active Hispanic-serving NGOs He also Organized two large health fairs for the Hispanic community

As a volunteer teacher and consular assistant, Mr Bañuelos was active in the Consulate's program for adult immigrants In that role, he assisted in processing passport applications, taught two classes in natural and social sciences to immigrants toward completion of their secondary education, and conducted computer and English classes

Lutheran Medical Center
New York, NY

Medical Health Project Field Researcher (2002)

Mr Bañuelos extensively interviewed over 500 Mexican men and women regarding their health care practices

Comercializadora Contry
Monterrey, Mexico

Executive Manager (1995-2001)

Mr Bañuelos negotiated sales and production of up to $25,000 per sale for uniform-making company He worked effectively with clients and suppliers, planned weekly objectives and monthly budgets, managed and supervised human resources and the maintenance of the work environment He designed and implemented winter sales program and increased client base and revenue by 40%

Education

Georgetown University

Executive Legal Assistant Certification Program (2003)

New York University

Certificate in U S Law Systems and Methodologies (2003)

University of Monterrey, Mexico

Bachelor of Business Administration (1999)

Languages

Fluent in Spanish

Trenise K. Queen

Experience

Snavely King Majoros O'Connor & Lee, Inc., Washington, D.C.
Analyst (2003)

Ms Queen provides technical and analytical assistance in the development of expert professional testimonies in the utility and transportation industries

Contact Team, Fairfax, Virginia
Researcher (2003)

Ms Queen worked as a researcher in the medical industry She acted as a liaison, in which she performed numerous contacts with medical facilities to discuss patient cases She screened patients on medical insurance verifications, application receivables, and prescription form follow-ups Ms Queen provided uninsured patients with alternative funding options for prescription coverage. Ms Queen also completed and proofread the filing applications and prescription forms for prescription medication eligibilities

University of Maryland, Princess Anne, MD
Lab Assistant (1999-2002)

Ms Queen worked as a lab assistant at the University of Maryland She assisted students with printer defaults, cable wiring, application knowledge engineering and troubleshooting of problems She also provided numerous seminars where she trained students on software applications

PEPCO, Washington, D.C.
Substation and Transmission Design Engineer (1997-2002)

Ms Queen worked for PEPCO performing engineering support functions. She performed upgrades of electrical power substation drawings, corrections to drawing retrieval information and scanning of drawings into the database, to incorporate design changes and modifications for the remolding and maintenance of the substations Ms Queen developed emergency signs drawings for fabrication, which was displayed at substations as a warning sign for pedestrians She supported the Engineering Group in the design and cost analysis by preparing spreadsheets for generated reports that produced the outcome of how much was being spent each year on transportation

University of Maryland, Princess Anne, MD
Engineering Assistant (1998)

Ms Queen was an Engineering Assistant at the University of Maryland. She developed AutoCAD drawings of building layouts and participated in building maintenance activities for the reconstruction of the campus Ms Queen issued and confirmed vehicle maintenance logs for extended travel and activities for faculty and students She used troubleshooting skills to foresee potential problems with vehicles and promptly took corrective actions to resolve difficulties and discrepancies that might cause problems in the future

Education

University of Maryland Eastern Shore, *B.S. in Electrical Electronics Engineering (2002)*

Professional Affiliations

Ms Queen is a member of Institute of Electrical Electronics Engineers and National Society of Black Engineers.

Mark A. Sam

Experience

Snavely King Majoros O'Connor & Lee, Inc., Washington, D.C.
Analyst (2003 to present)

Mr Sam provides technical and analytical assistance in the development of expert professional testimonies in the utility and transportation industries In connection with this work, Mr Sam has conducted research related to numerous state and Federal regulatory proceedings He has also aided in citation and editing of testimonies as well as the presentation of exhibits

Jakk's Pacific, Malibu, California
Account Executive (2002-2003)

Mr Sam managed various accounts and tracked inside sales for Jakk's Pacific a global toy distributor Mr Sam interacted with sales managers and clients to ensure that all transactions were completed satisfactorily He also supervised the introduction and launch of new items, directing inside sales on marketing techniques and sales parameters Mr Sam was the main contact for both clients and outside sales to ordering and distribution

FedEx, San Jose, CA
Coordinator (2000)

Mr Sam supervised the opening and functioning of a new terminal location at the outset of FedEx's new Home Delivery division Mr Sam devised business and recruiting plans for contract drivers, information systems, as well as contingency plans regarding terminal procedures He also was the primary liaison between drivers and district management as well as maintaining customer satisfaction for his terminal's jurisdiction Mr Sam also supported the terminal manager with cost analysis and quarterly projections

The Management Center, San Francisco, CA
Program Assistant (1998-2000)

Mr Sam worked as the Program Assistant at The Management Center, a nonprofit consulting firm in San Francisco California He conceived and implemented business plans for executive director training and best practices conferences Mr Sam also coordinated career and board-member recruitment fairs In both publicity and follow-up of these events, Mr Sam developed relationships with NBC, *The San Francisco Chronicle* and other major media outlets throughout the San Francisco Bay Area

Education

University of California, Berkeley
B.A. in Legal Studies (2002)
B.A. in African-American Studies (2002)

Professional Affiliations

Mr Sam is an active member of Kappa Alpha Psi Fraternity, Inc , a public-service and mentoring organization

Berkshire Consulting Services
386 Main Street
Ridgefield, Connecticut 06877
(203) 431-3012

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ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

December 6, 2004

Illona A Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Dear Ms. Jeffcoat-Sacco:

Thank you for sending us the Request for Proposal regarding assistance with the Commission staff in its investigation of Northern States Power Company's (NSP's) gas rate increase request. Because of our present commitments, we will not be sending a response to your request for proposal. However, we hope to continue receiving requests for proposal from your office and look forward to hearing from you in the future.

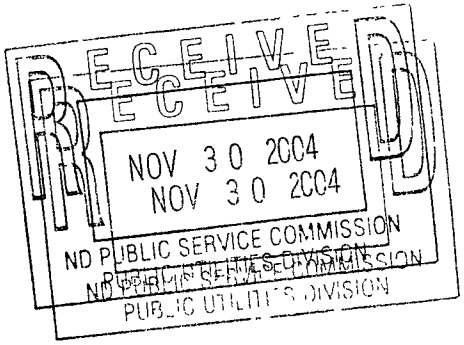
Sincerely yours,

David J. Effron

DJE/dd

29 PU-01-578 Pages 1
Notification that they will not be filing a response to RFP
by Berkshire Consulting Services
12/09/2004 CC Comm Legal PUD (4) Mike

JOHN S. THORNTON, JR
THORNTON FINANCIAL CONSULTING



November 24, 2004

Sharon D Helbling
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Dear Ms Helbling

Please find enclosed five copies of my original response to your recent Request for Proposal regarding the Northern States Power Company Gas Rate Case, North Dakota Public Service Commission Case No. PU-04-578

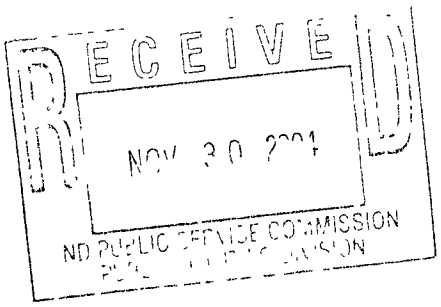
Please also find enclosed some additional letters of reference to include with my original filing

Yours sincerely,

John Thornton

10 **PU-04-578** Pages 57
Response to Request for Proposal
by Thornton Financial Consulting
11/30/2004 CC Comm Legal PUD, 4, wlke

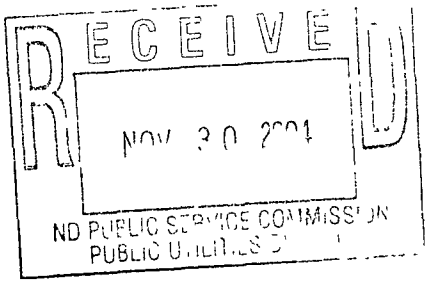
7929 EAST JOSHUA TREE LANE, SCOTTSDALE AZ 85250-7967 U.S.A.
PHONE: (602) 717-0730 • EMAIL: JOHN@THORNTONFINANCIAL.ORG



Letters of Reference

Oregon
John A Kitzhaber, M D , Governor

Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551
(503) 373-7394



January 24, 2001

Re: John S. Thornton, Jr.

To Whom It May Concern:

It is my great pleasure to offer this recommendation for John Thornton. I observed and worked with John at the Oregon Public Utility Commission for ten years.

John's expertise in finance and economics is unique. He was our lead analyst and witness for cost of capital. His testimony always withstood cross-examination. Based on his analysis and skill, the Commission prevailed routinely on cost of capital and return on equity issues, vital elements in any rate review.

John also testified and his position prevailed in a very complex pipeline rate case before the FERC. Such an achievement is indeed rare for an individual from a "small" state.

John participated effectively in alternative dispute resolution and in settlement agreements. Our staff is encouraged and empowered to use these methods to reach closure in contested cases.

John is a person of great integrity. I recommend him highly.

Joan H. Smith
Commissioner
503-378-6611

Oregon
John A Kitzhaber, M D , Governor

Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551
(503) 373-7394

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NOV 30 2004
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

March 12, 2001

To Whom It May Concern:

It is a pleasure to recommend John Thornton for employment with your firm. John served on the staff of the Oregon Public Utility Commission during my past eight-year tenure with the commission. He was a terrific asset to the commission and his departure has left a real gap in our ability to adequately perform financial analysis of utilities we regulate.

John is widely recognized throughout the regulatory community for his expertise and tough scrutiny of capital structure and risk factors in determining appropriate rates of return. He testified effectively in numerous major rate cases before the commission, and he provided helpful research to commission members on an ongoing basis.

John always performed his duties with the highest professional integrity. The result was a great service and benefit to Oregon utility consumers.

John also served the commission in other ways not specifically related to his field of economic analysis. He facilitated the selection of art displays from the state fund allocation to the PUC building, and was an active participant in ethnic diversity events. His efforts and concerns benefited our employees in a number of ways that were not directly rewarded but left a memorable legacy to the agency and its employees.

I am enthusiastic in recommending John for employment and am confident he will make a great contribution to your company or agency.

Sincerely,

Roger Hamilton
Public Utility Commissioner

Oregon
John A. Kitzhaber, M.D., Governor

Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2557
(503) 373-7394

February 5, 2001

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ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

To Whom It May Concern

RE: John Thornton

I am pleased to tell you about the professional qualifications and experience of John Thornton. My knowledge of these things is based on a 13-year professional relationship with John at the Public Utility Commission of Oregon (OPUC) that began when I hired him in 1988. I know John and his work well and feel that he would be a strong addition to any staff.

John's primary duty at the OPUC was to serve as the agency's cost of capital expert. Basically, this meant that John recommended allowed rates of return for regulated utilities. In order to do this job well, John needed to have an outstanding knowledge of finance theory, econometrics/statistics, and regulation. He also needed to write well because expert witnesses submit prefiled written testimony. Finally, John had to be able to think on his feet while being cross-examined by company attorneys.

John also has a practical knowledge of finance. This was gained through his involvement with utility company financings, which must be approved by the OPUC. John has an excellent knowledge of modern financing and hedging instruments.

John also worked on a number of major merger dockets. This work required him to become an expert on merger details.

John is quite personable. He has shown the ability to work well by himself and as part of a team.

Please contact me if I can provide further information about John.

Phil Nyegaard

Phil Nyegaard
Administrator, Telecommunications Divison
Public Utility Commission of Oregon
(503) 378-6436
phil.nyegaard@state.or.us

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NOV 30 2004
ND PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION

January 29, 2001

Re: Letter of Reference for John S. Thornton

To Whom It May Concern:

Prior to my retirement in February, 1998, I was Program Manager for Energy Utility Revenue Requirements for the Public Utility Commission of Oregon. I held that or a similar position for about 15 years. Among my responsibilities was leadership of teams formed to analyze and respond to voluminous and complex financial filings, normally in support of proposed rate increases, by regulated electric and gas utilities. Mr. Thornton was usually a member of those teams, responsible for making the PUC Staff's proposals concerning reasonable costs of capital.

The PUC of Oregon's Staff was relatively small in number. Even though a team of analysts worked on each review, assigned individuals worked independently. Because cost of capital determinations had such a large effect on allowable revenues, regulated companies placed great emphasis on the area. Mr. Thornton had to critique and respond to the work of experts in the field, often highly paid consultants. The projects required a combination of outstanding technical ability and exceptional communications skills Mr. Thornton's work always met the highest quality standards.

Resolution of these projects required negotiations with a number of parties and, if agreement could not be reached, presentation and defense of sworn testimony in a quasi-judicial setting. Mr Thornton was always well prepared and vigorous in supporting his recommendations.

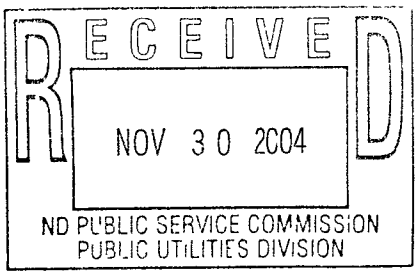
In short, Mr. Thornton does very good work in a highly complex field, can clearly explain what he has done and why, and, thus, defends his recommendations effectively. He would be an asset to any organization needing those skills and abilities.

Please feel free to contact me if you want or need more information.

T. Ray Lambeth

T Ray Lambeth
542 Stagecoach Way SE
Salem, Oregon 97302
(503) 370-9470
e-mail terryray.lambeth@prodigy.net

February 5, 2001



To Whom It May Concern:

I am pleased to recommend John S. Thornton, Jr. with whom I have worked for 13 years.

John will invest whatever time and effort is necessary to insure that all functions in which he is involved reflect well on the organization and are of the highest professional standards. He is serious about the team product and having a positive effect on the organization. He accomplishes this through hard work, integrity, and intellectual pursuit.

John has the ability to present both written and oral arguments about a technical subject so that they are understandable to people who are not experts in that field. His arguments are logical, consistent with prior positions, and are presented in a manner that addresses the matter intellectually, rather than attacking the adversary. This says a great deal about John's integrity and intelligence.

John is an outstanding candidate for a job that involves relationships with foreign countries or companies. He is people oriented and maintains active friendships with people in several countries.

If I can be of further assistance please contact me at the address or phone number below.

David T. Werner

David T. Werner, CPA
Lt. Colonel, USAF Retired
14450 NW Pheasant HILL Rd.
McMinnville, OR 97128-8045
Phone (503) 472-5508

SURPRISINGLY COST EFFICIENT SERVICES

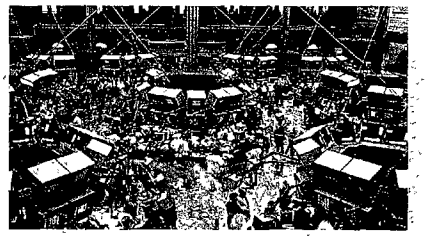
You will likely be surprised at the cost effectiveness of bringing **TFC** to your case at hand compared to a fully-loaded salary More importantly, you will be even more surprised at the high quality of service and excellent results you will get with an experienced and well placed consultant who is concerned about value and your satisfaction

JOHN THORNTON, M.Sc., Grad. Dip., C.R.R.A.

John Thornton is a graduate of **The London School of Economics and Political Science** where he specialized in corporate finance He has testified on utility finance for over sixteen years and has successfully prosecuted cases ranging from utility rates to the first foreign purchase of a U S utility.

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for a
no-obligation consultation



Modern capital markets determine the cost of capital to a utility Therefore, modern capital market theory must be used to estimate that cost of capital

Thornton Financial Consulting

Serving utility consumers, regulators & utilities in rate cases, mediations, and a variety of regulatory dockets



Thornton Financial Consulting

John Thornton, M Sc., Grad Dip , C R.R.A.
7929 E Joshua Tree Lane
Scottsdale, AZ 85250-7967
Tel (602) 717-0730
email john@thorntonfinancial.org

Thornton Financia Consulting

Financial Analysi of the Utility Industry

Expert Witness Testimony



Tel: 602.717.0730

www.thorntonfinancial.org

[John Thornton's] analysis was detailed, concise, thorough, and very helpful in the decision making process on rate cases.

Marc Spitzer Esq., Chairman, Arizona Corporation Commission, 2004

UTILITY FINANCE

Utility finance is a complicated enough matter for a commission staff or intervenor to tackle, but even more so when understaffed or overworked **TFC** offers a wide variety of individually tailored solutions to the specific finance issues facing your utility industry Cost of capital testimony, utility merger ring fencing solutions, utility finance application assistance, and affiliate transaction pricing are but a few key solutions **TFC** offers.

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TFC can bring the value of extensive industry experience to bear on your next utility finance problem You will benefit from increased but temporary staff **TFC** can improve your own staff's skills in the area of utility finance including cost of equity estimation and multiple discriminant analysis

COST OF CAPITAL TESTIMONY

1 Cost of equity analysis has become an increasingly complex field. **TFC** offers the very best in analytical techniques that are defensible and can more accurately estimate the cost of equity to a utility The field has become multi-disciplinary, including skills in finance, accounting, economics, statistics, econometrics, and mathematics **TFC** can augment your staff in these critical skills to prosecute a case successfully **TFC** has multiple files, data sources, and experience in the witness box

The cost of equity has fallen with the decline of interest rates. Commission staffs and intervenors should be seeking lower ROEs in utility rates.

2 Cost of debt analysis also brings its own complications The RBOCs had attempted to use the net-book-balance method to set their cost of debt. An expert witness trained in finance and mathematics could explain the problems inherent in the method which lead to higher rates than were appropriate

3 Capital structure requires an increasing degree of experience and analysis A historical test period capital structure can actually harm a utility and can be inconsistent with financial health going forward. Debt at the holding company level can also affect an appropriate rate of return

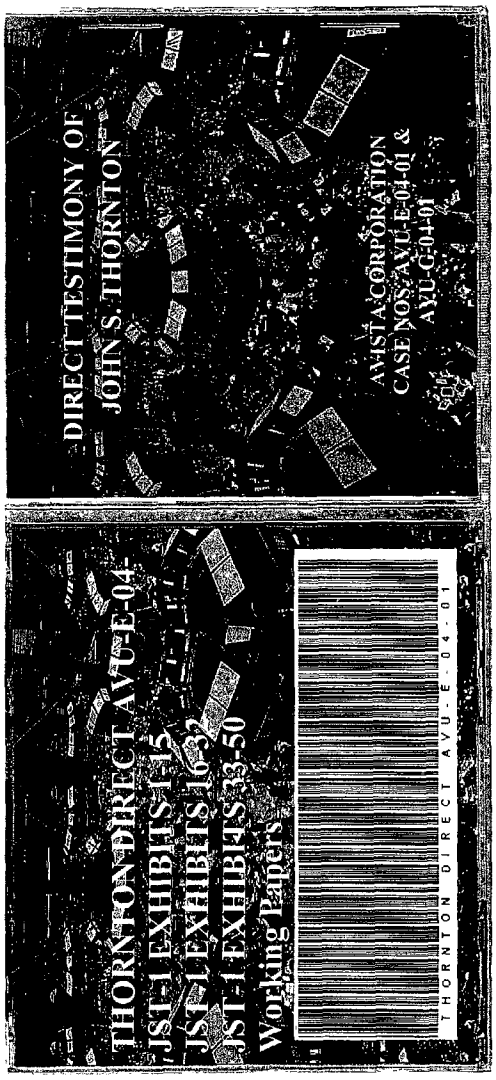
The $10 million mistake: Not harnessing uniquely specialized experience in cost of equity analysis.

MERGER & ACQUISITION ASSISTANCE

Mergers and acquisitions are complex and subje increasing scrutiny **TFC** has experience in ring fencing procedures, including those that protecte PGE from the Enron bankruptcy **TFC** also has perience with mergers between domestic utilities and foreign purchases of domestic utilities Mer ers and acquisitions are becoming increasingly c plex and require increased scrutiny Bring some experienced consultation to bear on your next merger case to generate a better outcome for all ties

EXPERT WITNESS TESTIMONY AND TRAINING

TFC has logged many hours on the witness stan and has the training and experience needed to m your case successful **TFC also offers seminar expert witness testimony for your staff so tha you can develop or improve internal skills to sent cases independently.**



Serving utility consumers, regulators & utilities in rate cases, mediations, and a variety of regulatory dockets



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THORNTON FINANCIAL CONSULTING

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You need a witness that makes your job easier so that you can concentrate on process, procedure, argumentation, and winning a case on behalf of your client.

Thornton Financial Consulting makes every effort to make your work easier. A high quality on-time and on-budget work product has always been a regular expectation. Now, **TFC** offers a complete work product on CD-ROM. Testimony and hardcopy exhibits are supplied in Adobe Acrobat© for easy filing, copying and Web posting.

Discovery is greatly enhanced because all working papers are included on the same CD-ROM as testimony and exhibits Working papers are included in their original computer formats (Excel, Word, etc.) or scanned into Adobe Acrobat© and they are never password protected This all means that discovery requests are a simple CD-ROM copy away. Working papers on the CD-ROM are supplied with the original hardcopy testimony so that no unnecessary billing time is incurred in supplying working papers during discovery

A WITNESS THAT MAKES YOUR WORK EFFICIENT

All it takes to copy and provide an entire witness work product is a few mouse clicks and a CD-R. No need to incur excessive time and money in making, coordinating, and shipping multiple hardcopies One CD-ROM is all it takes, reducing your in-house staff expense and reducing case costs.

Your central case files will be greatly enhanced by a complete record on a single CD-ROM.

Note confidential testimony, exhibits, and working papers are generally not provided on CD-ROM unless requested in order to protect parties' confidentiality.



Utility finance deserves the best of financial economics. Bring TFC to bear on your next case.

A WITNESS THAT MAKES YOUR TEAM SHINE

You benefit from a witness that offers the most scientific financial economics available in the utility industry along with extensive experience in many aspects of utility rate making. However, you can also benefit from a witness who is concerned about your legal team's efficiency and your client's budget.



JOHN S. THORNTON
M.Sc., Grad. Dip., C.R.R.A.

JOHN S. THORNTON, JR.
M.Sc., Grad. Dip., C.R.R.A.

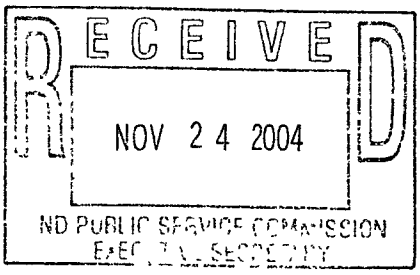
Financial Economist & Expert Witness in Utility Rates

7929 EAST JOSHUA TREE LANE
SCOTTSDALE, AZ 85250-7967 U.S.A.
TEL: 602 717 0730

JOHN@THORNTONFINANCIAL.ORG

JOHN S. THORNTON, JR
THORNTON FINANCIAL CONSULTING

November 22, 2004



Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol, 12th Floor
Bismarck, North Dakota 58505-0480

Dear Ms. Jeffcoat-Sacco:

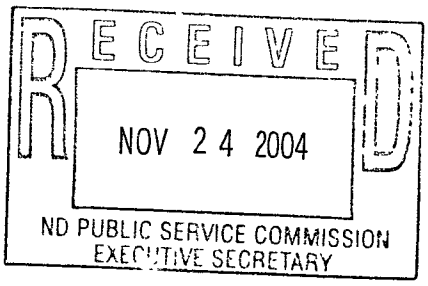
I am pleased to submit a response to your recent Request for Proposal regarding the Northern States Power Company Gas Rate Case, North Dakota Public Service Commission Case No. PU-04-578.

Please do not hesitate to call me should you or your staff have any questions about the enclosures or my experience as a utility analyst and expert witness.

Yours sincerely,

John Thornton

7929 EAST JOSHUA TREE LANE, SCOTTSDALE AZ 85250-7967 U.S.A.
PHONE: (602) 717-0730 • EMAIL: JOHN@THORNTONFINANCIAL.ORG



Request For Proposal Submission

Rate of Return Analysis and Testimony

Northern States Power Company Gas Rate Case

North Dakota Public Service Commission Case No. PU-04-578

By

John Thornton, M.Sc., Grad. Dip., C.R.R.A.
Thornton Financial Consulting

November 22, 2004

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Scope of Work:

The general scope of the work is limited to the rate of return. Within that subject field, the contractor will provide the following:

(1) professional analysis and review of the filing;
(2) prepare and conduct discovery;
(3) prepare and file written direct testimony;
(4) appear and provide oral testimony for up to two days of hearings;
(5) assist NDPSC staff and its attorneys in preparing cross examination of opposing witnesses;
(6) assist staff and its attorneys in preparing proposed findings of fact and any post-hearing brief;
(7) provide monthly progress reports regarding the work product.

Proposed Work Approach

Mr. Thornton proposes working through staff and its attorneys to send data requests of Northern States Power Company's (NSP) prefiled written direct testimony. All original working papers and analyses will then be examined for mathematical and theoretical accuracy. Data requests will also be sent out to independently examine the historical financial health and future financial plans for NSP and its gas distribution operations.

Mr. Thornton's independent findings and his conclusions regarding NSP's case will then be presented in draft form to staff and its attorneys before final filing. The following areas will be examined in particular:

The Cost of Equity

Mr. Thornton will apply accurate, experienced, solid and defensible DCF and CAPM analyses in estimating the cost of equity to NSP's gas service area customers. He will also examine and critique NSP's witness on the subject. Particular areas of inquiry might include the small company risk premium and the flotation cost adjustment. NSP-Minnesota presented these two issues in its recent Minnesota gas rate case (Robert Hever, September 17, 2004).

The Cost of Debt and Preferred Stock

Mr. Thornton will investigate and testify to the appropriate costs of debt and preferred stock using the internal rate of return method to derive the all-in costs. Any floating-rate debt or preferred stock would be priced at some reasonable and most current rate.

Capital Structure

Mr. Thornton will also examine capital structure issues such as the reasonableness, reliability and relevance of the company's proposed capital structure. Any number of issues can arise in such an investigation including hypothetical capital structure issues and double leverage at the Xcel Energy, Inc. level.

Capability:

Experience

John Thornton has appeared in numerous general gas rate cases and deferred gas cost rate cases. Please see the attached Witness Qualifications Summary for a listing of the cases in which he has appeared. Previous to testifying independently, Mr. Thornton was the Chief of the Financial and Regulatory Analysis Section of the Utility Division, Arizona Corporation Commission (ACC). The Financial and Regulatory Analysis Section was the core unit responsible for revenue requirement and rate design for utilities regulated by the ACC. Previous to his work at the ACC, Mr. Thornton was a Senior Economist with the Oregon Public Utility Commission for thirteen years. Consequently, Mr. Thornton brings vastly more experience to the project than the core area of rate of return.

Education

John Thornton holds two graduate degrees from The London School of Economics and Political Science. His M.Sc. in Economics focused on finance and he studied under Mervyn King of the "New School" of corporate finance. Mr. Thornton believes that he can bring the most quantitatively accurate cost of equity education and analysis available to the North Dakota Public Service Commission.

Performance Record

Mr. Thornton has had particular success in countering company witness claims that would otherwise result in unfairly high rates of return. Mr. Thornton has personally testified against well-known and highly paid company witnesses such as Dr. Roger Morin, Dr. James Vander Weide, and Dr. William Avera.

Résumé

Please see attached résumé and Witness Qualifications Statement.

Sample Work Product

Please see attached sample work product for an example of Mr. Thornton's most recent analyses in two separate cases.

Past Three Clients

CONLEY WARD ESQ
GIVENS PURSLEY
601 W BANNOCK ST
BOISE ID 83710
Tel: (208) 388-1200

MARTHA J. ASHCRAFT, ESQ.
LEWIS AND ROCA LLP
3993 HOWARD HUGHES PKWY.
SUITE 600
LAS VEGAS, NV 89109
TEL: (702) 949-8200

MELINDA J DAVISON, ESQ.
DAVISON VAN CLEVE
1000 SW BROADWAY
SUITE 2460
PORTLAND OR 97205
TEL: (503) 241-7242

Conflict of Interest

Mr. Thornton is unaware of any conflicts of interest that would prevent him from testifying in this case on behalf of the NDPSC. Please see attached Affidavit of Conflict of Interest Disclaimer.

EEOC/ADA Certification

Thornton Financial Consulting complies with all EEOC and ADA laws.

Price

The proposed fixed price of the project is $25,000 including all travel, hotel, copying, shipping, and miscellaneous expenses. The fixed price is payable 3/4 upon filing direct testimony and the balance within sixty days of final invoice.

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NOV 24 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Résumé
and
Witness Qualifications Statement

JOHN S. THORNTON, JR.
7929 EAST JOSHUA TREE LANE • SCOTTSDALE, AZ 85250-7967 USA
TEL: 602.717.0730 • WEBSITE: www.thorntonfinancial.org • EMAIL: john@thorntonfinancial.org

SUMMARY

Finance professional with a broad background testifying in corporate finance, financial analysis, and cost-of-capital estimation. Extensive experience as an expert witness in state and federal proceedings Chief financial analyst or team member on merger/acquisition review teams for Portland General Electric/Enron, PacifiCorp/ScottishPower, Portland General Electric/Sierra Pacific Resources, and RWE/Arizona American Water Co. Customarily works on several projects simultaneously and on multiple schedules in addition to management and leadership responsibilities Skilled in negotiating and alternative dispute resolution Experienced in spreadsheet, statistical, and econometric software. Lived in the Middle East and the United Kingdom and traveled abroad extensively

PROFESSIONAL EXPERIENCE

THORNTON FINANCIAL CONSULTING, Scottsdale, Arizona — December 2003 – Present

Principal

Consulting firm in utility finance established to provide expert witness testimony on the cost of capital to utilities. Developed an analytical method to solve the "distribution risk discount," an original divisional cost of capital approach for estimating the cost of equity facing an electric distribution firm.

- Testified on behalf of the State of California in restructured electricity pricing proceedings involving Pacific Gas & Electric Co., Southern California Edison, and San Diego Gas & Electric Co., Application Nos. 98-05-019, 021, & 024 (1999)
- Testified on behalf of Mirage Resorts, Inc., Park Place Entertainment Corp., and The Mandalay Group in Nevada restructured electric pricing proceedings in Docket Nos. 99-4001 and 99-4005 re Sierra Pacific Power Co compliance filing and Nevada Power Co. compliance filing (2000).
- Testified on behalf of the Attorney General of the State of Washington and the Industrial Customers of Northwest Utilities in Avista rate case Docket No. UE 010395 (2001).
- Testified on behalf of Mirage Resorts, Inc , Park Place Entertainment Corp., and The Mandalay Group in a Nevada Power Co. general rate case Docket Nos. 01-10001 and 01-10002 (2002)
- Testified on behalf of MGM Mirage Resorts, Inc. in Nevada Power Co. general rate case 03-10001 (2004).
- Testified on behalf of Potlatch Corporation. in Avista Corp.'s general rate case AVU-E-04-01(2004).
- Analyzed the proposed acquisition of Portland General Electric by the Texas Pacific Group from the Enron bankruptcy estate on behalf of the Industrial Customers of Northwest Utilities.

ARIZONA CORPORATION COMMISSION, Phoenix, Arizona — 2001 – Jan 2004

Chief, Financial & Regulatory Analysis Section, Utility Division

Lead a team of sixteen finance and accounting professionals primarily responsible for setting utility rates in the state of Arizona.

- Provided financial and regulatory advice in key dockets as both Staff witness and commissioner-advisor.
- Provided leadership direction to resolve corporate culture issues from technical skills to effective work habits.
- Developed orientation program and in-house training seminars on expert-witness testimony.
- Wrote position descriptions and performance evaluation criteria.
- Performed range of managerial duties including interviewing, performance appraisals, & coaching.
- Advised ACC Director and Commissioners on state, regional, and national issues.
- Hired, trained, and promoted employees with a goal of improving workplace effectiveness and employee success.
- Worked with industry to develop appropriate regulatory responses to current issues, such as the effect on water costs from new Environmental Protection Agency regulations and responses to credit issues in the energy industry.
- Lead negotiations and alternative dispute resolutions in gas, telephone, electricity, water, and wastewater rate cases and utility mergers.

PUBLIC UTILITY COMMISSION OF OREGON, Salem, Oregon 1988 – 2001

Senior Financial Economist

Corporate finance expert witness. Provided expert witness testimony in utility rate cases regarding corporate finance, including the costs of equity, debt, preferred stock, derivatives, and mergers Testified before the Federal Energy Regulatory Commission. Provided in-house expertise on corporate finance and capital budgeting

- Successful track record of negotiating or winning in administrative hearings over $400,000,000 of utility rate reductions for Oregonians through 2000.
- Reviewed and recommended approval of over one hundred securities issuance proposals including medium-term notes, first mortgage bonds, debentures, revolving credit facilities, derivatives, and others.
- Presented a regulatory finance paper before the Colombian Minister of Mines and Energy, Cartagena Colombia World Conference on the Electric Power Sector in Colombia. Spoke before visiting delegations from Russia, Thailand, Japan, Zaire, and the Philippines on issues of corporate finance
- Defended expert witness testimonies before state and federal jurisdictions regarding mergers, costs of capital, corporate finance policy, financial accounting, statistics, and econometrics

INDUSTRIAL SUPPLY CO., INC., Salt Lake City, Utah 1999 – Present

Director

Member of the Board of Directors of an award-winning and closely-held distributor of industrial supplies. Based in Salt Lake City, Utah with distribution in the Intermountain West.

- Worked on common stock repurchase program to efficiently consolidate ownership structure.
- Developed preferred stock repurchase program to minimize tax impact of estate transfer

EDUCATION

Master of Science, (Financial) Economics,
The London School of Economics and Political Science, London, England, 1986

Graduate Diploma, (International) Economics,
The London School of Economics, London, England, *Awarded with Credit*, 1985

Bachelor of Science, Economics,
Willamette University, Salem, Oregon, *College Honors List*, 1984

RELATED STUDIES AND CERTIFICATIONS

Georgetown University, Washington D.C., *Dean's List*, 1979-1981
Willamette U. Atkinson Graduate School of Management, Salem, Oregon, *Graduate level studies in finance, statistics and accounting*

Certified Rate of Return Analyst
Passed level 1 of the Chartered Financial Analyst exam series

Witness Qualifications Statement

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ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

NAME: JOHN S. THORNTON, JR.

ADDRESS: 7929 E Joshua Tree Lane, Scottsdale AZ 85250-7967

EDUCATION: Master of Science Degree from the University of London, having completed the graduate program in economics at The London School of Economics and Political Science (1986)

Graduate Diploma in Economics from The London School of Economics (1985)

Bachelor of Arts degree, major in economics, from Willamette University (1984)

Certified Rate of Return Analyst, member of the Society of Utility and Regulatory Financial Analysts

1998 passed level I of the CFA
1995 PaineWebber Seminar on Corporate Finance for the Utility Industry
1990 MIT/Harvard Public Disputes Resolution Program seminar
1990 National Association of Regulatory Utility Commissioners (NARUC) Advanced Regulatory Studies Program
1988 NARUC Annual Regulatory Studies Program

EXPERIENCE: **Chief, Financial & Regulatory Analysis Section, Utilities Division, Arizona Corporation Commission, 2001 to 2004**

Testified or provided reports in the following dockets:

•W-01656A-98-0577 & WS-02334A-98-0577—Sun City Water Co. and Sun City West Utilities Co.'s request for approval of the Central Arizona Project water utilization plan. Testimony on the effect of the Groundwater Savings Project on Sun City Water Co. and Sun City West Utilities Company's revenue requirement.

•E-01345A-02-0707—Arizona Public Service Co.'s application for authority to incur $500,000,000 of debt and to acquire a financial interest in an affiliate by lending $500,000,000 to Pinnacle West Capital Corp. or Pinnacle West Energy Corp. Alternatively, APS' application to guarantee $500,000,000 of PWCC or PWEC debt. Testimony on the appropriateness of the affiliate transactions and seven conditions under which the loan could be made.

•E-01345A-02-0840—Arizona Public Service Co.'s application for authority to loan $125,000,000 of debt to an affiliate. (Staff report regarding four conditions under which the affiliate transaction would be appropriate.)

Witness Qualifications Statement (continued)

•E-01345A-02-0403—Arizona Public Service Co.'s application for approval of adjustment mechanisms. Testimony on a power supply adjustor earnings test.

•E-01032-00-0751, G-01032A-02-0598, E-01933A-02-0914, E-1032C-02-0914, G-01032A-02-0914—Consolidated dockets of UniSource, Citizens Communications Arizona Gas Division (AGD), & Citizens Communications Arizona Electric Division (AED); general rate case for the AGD, PPFAC adjustment for AED, and sale of AGD and AED to UniSource. (Staff report section on analysis of the financing of the sale and transfer of utility assets.)

•W-01445A-02-0619—Arizona Water Company's application for rates and charges for eight systems. Testimony on implementing lifeline rates and marginal cost pricing into rate design, resulting in inverted block rates.

Senior Analyst with the Public Utility Commission of Oregon, 1988-2001

Testified or provided rate of return analyses in the following dockets:

•UE 102—PGE disaggregation/general rate case (chief rate of return witness).

•UE 94—PacifiCorp general rate case (chief rate of return witness).

•UE 93 (UM 592, UM 694)—Portland General Electric Co. excess power cost/Coyote/BPA filing.

•UE 92—Idaho Power general rate case.

•UE 88—Portland General Electric Co. general rate case (chief rate of return witness).

•UE 85/UM 529—Portland General Electric Co. Earnings test for Trojan Shutdown Cost Adjustment Account.

•UE 84—Idaho Power Co. deferred account earnings benchmark.

•UE 82/UM 445—Trojan Outage Cost Adjustment Account earnings test benchmark.

•UE79—Portland General Electric Co. general rate case (chief rate of return witness).

•UG 104/UG 105/UG 106—LDC deferred account earnings test benchmarks.

•UG88—Cascade Natural Gas Co. general rate case (chief rate of return witness).

•UG81—Northwest Natural Gas Co. general rate case (chief rate of return witness).

•UT 125—US WEST Communications, Inc general rate case (chief rate of return witness).

•UT 113—GTE Northwest general rate case (chief rate of return witness).

•UT101—United Telephone Co. of the Northwest general rate case (chief rate of return witness).

•UT85—US WEST general rate case (capital structure and debt cost witness).

•RP95-409—Northwest Pipeline general rate case (FERC).

•RP93-5—Northwest Pipeline general rate case (FERC).

Responsibilities also included the following:

•Analyses and recommendations in over fifty financing dockets involving instruments such as first mortgage bonds, medium-term notes, debentures, preferred stock, QUIDS, TOPRs, common equity, shareholder rights plans (poison pills), and derivative securities including caps, collars, and floors.

•UM 903— Northwest Natural, cost of capital analysis for purchased gas adjustment mechanism.

•UM 21—Cost of capital analysis for avoided cost calculations.

•UM 351—Cost of capital analysis for long-run incremental-cost studies.

•UM 573—Analysis of purchased power on the utility's cost of capital.

•UM 773—Cost of capital analysis for long-run incremental-cost studies.

•UM 814—Enron's application to acquire Portland General Electric Co.

•UM 918—Scottish Power plc's application to acquire PacifiCorp.

•UM 967—Sierra Pacific Resource's application to acquire Portland General Electric Co.

Thornton Financial Consulting - Principal

Speaker—US Agency for International Development's Conference on Private Sector Participation in the Colombian Power Sector. (1991)

Witness Qualifications Statement (continued)

Application Nos. 98-05-019, 021, & 024. Presented beta adjustment and distribution risk discount testimony on behalf of the Division of Ratepayer Advocates of the California Public Utility Commission.

Docket Nos. 99-4001 and 99-4005 re Sierra Pacific Power Co. compliance filing docket no. 99-4001 and Nevada Power Co. compliance filing docket no. 99-4005. Rate of return witness for intervenors Mirage Resorts, Inc., Park Place Entertainment Corp., and the Mandalay Group.

Docket No. UE 010395 re: application of Avista Corporation d/b/a Avista Utilities request for recovery of power costs through the deferral mechanism. Corporate finance witness for the Industrial Customers of Northwest Utilities.

Docket Nos. 01-10001 and 01-10002 re: application of Nevada Power Co. for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto: Rate of return witness for intervenor MGM-Mirage.

Docket Nos. 03-10001 and 03-10002 re: application of Nevada Power Co. for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto: Rate of return witness for intervenor MGM-Mirage.

Docket No. UM 1121 re: application of Oregon Electric Utility Company to acquire Portland General Electric Co. from the Enron estate. Merger & acquisition analysis on behalf of the Industrial Customers of Northwest Utilities. (2004)

Docket No. E-04230A-03-0933 re: application of KKR to acquire UniSource Corporation. Transaction analysis and commentary for Gerson Lehrman Group, Inc.

Case Nos. AVU-E-04-01 and AVU-G-04-01 re: application of Avista Corporation for authority to increase its electric and natural gas rates. Rate of return witness for intervenor Potlatch Corporation. (2004)

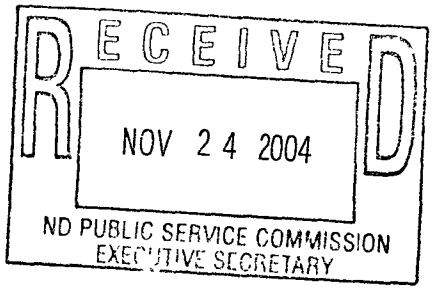
Analyzed the proposed acquisition of Portland General Electric by the Texas Pacific Group from the Enron bankruptcy estate on behalf of the Industrial Customers of Northwest Utilities. (2004)

Sample Work Product

Ex. 201

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	Case Nos AVU-E-04-1 AVU-G-04-1

DIRECT TESTIMONY OF JOHN S. THORNTON

ON BEHALF OF POTLATCH CORPORATION

June 21, 2004

EXECUTIVE SUMMARY
PREFILED DIRECT TESTIMONY OF
JOHN S. THORNTON, JR.

CASE NOS. AVU-E-04-01 & AVU-G-04-01
AVISTA CORPORATION

Mr Thornton testifies to Avista Corporation's (Avista) appropriate return on equity (ROE) and overall rate of return (ROR) that should be allowed in rates Mr. Thornton recommends an 8 5 percent return on common equity based on his capital asset pricing model and discounted cash flow model analyses of the cost of equity to the electric utility industry He recommends an 8 49 percent overall rate of return

Mr Thornton addresses Mr Malquist's prefiled direct testimony regarding the return on equity, the cost of debt and preferred stock, the capital structure and the rate of return Mr Thornton expresses concern that Mr Malquist recommends an 11.5% ROE based on his personal beliefs without any financial or economic analysis

Mr Thornton also addresses the prefiled direct testimony of Dr. William Avera Dr Avera presents cost of equity analysis to support Mr. Malquist's return on equity recommendation Dr Avera testifies that the 11 5% ROE request represents a conservative estimate of the cost of equity to Avista. Mr Thornton discusses the problems with Dr Avera's analyses that lead to Dr Avera's upwardly biased estimates of the cost of equity.

Prepared Direct Testimony of John S. Thornton, Jr.
Avista Corporation
Case Nos. AVU-E-04-01 & AVU-G-04-01
June 21, 2004

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Witness Identification

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is John S Thornton, Jr and my business address is 7929 East Joshua Tree Lane, Scottsdale AZ 85250.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A I am an independent consultant in utility finance I appear as a witness on behalf of Potlatch Corporation

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I hold a Master of Science degree from the University of London, having completed the Master's program (economics with specialty in corporate finance) at The London School of Economics and Political Science (The LSE) I also hold a Graduate Diploma from The LSE I have participated as a cost of capital expert in numerous electric utility, local gas distribution, and telephone cases in the states of Oregon, Washington, California, Nevada, and Arizona, and I participated in gas pipeline cases before the Federal Energy Regulatory Commission I was a Senior Economist for the Public Utility Commission of Oregon and its chief rate-of-return witness I recently left my position as the Chief of the Financial and Regulatory Analysis Section of the Arizona Corporation Commission's Utility Division to consult independently My background is described further in my Witness Qualifications Statement found on pages 48-50 of Exhibit JST–1

Scope of Testimony

Q. WHAT WAS YOUR ASSIGNMENT IN THIS CASE?

A My assignment was to estimate a fair return on equity (ROE) and rate of return (ROR) for Avista Corporation's electric and gas utility operations in this proceeding. I also reviewed Avista Corporation's testimony on the rate of return prepared by Malyn Malquist and cost of equity testimony prepared by Dr William Avera

Summary Recommendation

Q. PLEASE SUMMARIZE YOUR FINDINGS ON AVISTA CORP.'S COST OF EQUITY AND RATE OF RETURN.

A I estimate Avista Corp 's cost of equity to be 8.5 percent. I recommend an 8.49 percent rate of return, calculated on page 1 of Exhibit JST-1 I also offer ROR calculations incorporating the high and low end of my cost of equity estimates

Q. WHAT DID YOU FIND IN YOUR REVIEW OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. I found that Mr Malquist recommends an 11 5 percent return on equity He provides no cost of equity analysis or reasoning behind his recommendation other than a belief that "the 11.5% provides a reasonable balance of the competing objectives of regaining financial health within a reasonable period of time, and the impacts that increased rates have on our customers " (*See* Direct Testimony of Malyn Malquist, page 22 at 3 to 6.) He also believes that a return on equity greater than 11 5 percent is supported and warranted.

Q. SHOULD THE COMMISSION ADOPT AN 11.5 PERCENT ROE BASED ON MR. MALQUIST'S BELIEFS?

A No, the Commission should not adopt an 11 5 percent ROE based on Mr Malquist's beliefs, which are absent of any financial or economic analysis on his part Mr Malquist's testimony is also inconsistent with Avista's actions Avista recently increased its dividend, thereby draining cash from the utility, and Avista fully intends to increase its dividend further I would recommend that Avista retain that cash, build its equity position or pay off debt and thereby improve its financial health In Avista's May 25, 2004, Webcast conference, I understood Mr Malquist to say that Avista would have been increasing dividends even further if it were not for a restrictive bond covenant that limited dividend increases. In other words, Avista is not sufficiently committed to building its own financial house internally. Avista prefers to improve its financial health through higher rates at the expense of ratepayers.

Q. WHAT IS THE PURPOSE OF DR. AVERA'S TESTIMONY?

A Dr Avera's purpose is to present his evaluation of Avista's current cost of equity for Avista's jurisdictional electric operations. (*See* Direct Testimony of Dr. William Avera, page 3 at 7 to 9) He concludes that Avista's cost of equity significantly exceeds 11 5 percent

Q. WHAT DID YOU FIND IN YOUR REVIEW OF DR. AVERA'S ANALYSIS?

A I found that his results are upwardly biased and should not be used to set the ROE in this case

Capital Structure

Q. WHAT IS AVISTA CORPORATION'S RECOMMENDED CAPITAL STRUCTURE?

A Avista Corporation's recommended capital structure is found in the Prefiled Direct Testimony of Malyn K Malquist. He recommends the following September 30, 2004, pro forma capital structure.

Avista Corporation Filed Capital Structure	
Debt	48 19%
Trust Preferred Securities	5 79%
Preferred Equity	1.72%
Common Equity	44 30%

Q. DO YOU RECOMMEND ANY CHANGES TO MR. MALYN'S PRO FORMA CAPITAL STRUCTURE?

A. No

Fair and Reasonable Return on Equity

Q. HOW DO YOU DEFINE THE TERM "COST OF EQUITY?"

A A firm's cost of equity is that rate of return on equity that investors expect to earn on their equity investment given the risk of the firm. Investors' expected return is equally defined as the return on equity that they expect on other investments of similar risk [1] My testimony on Avista Corporation's cost of equity starts with a

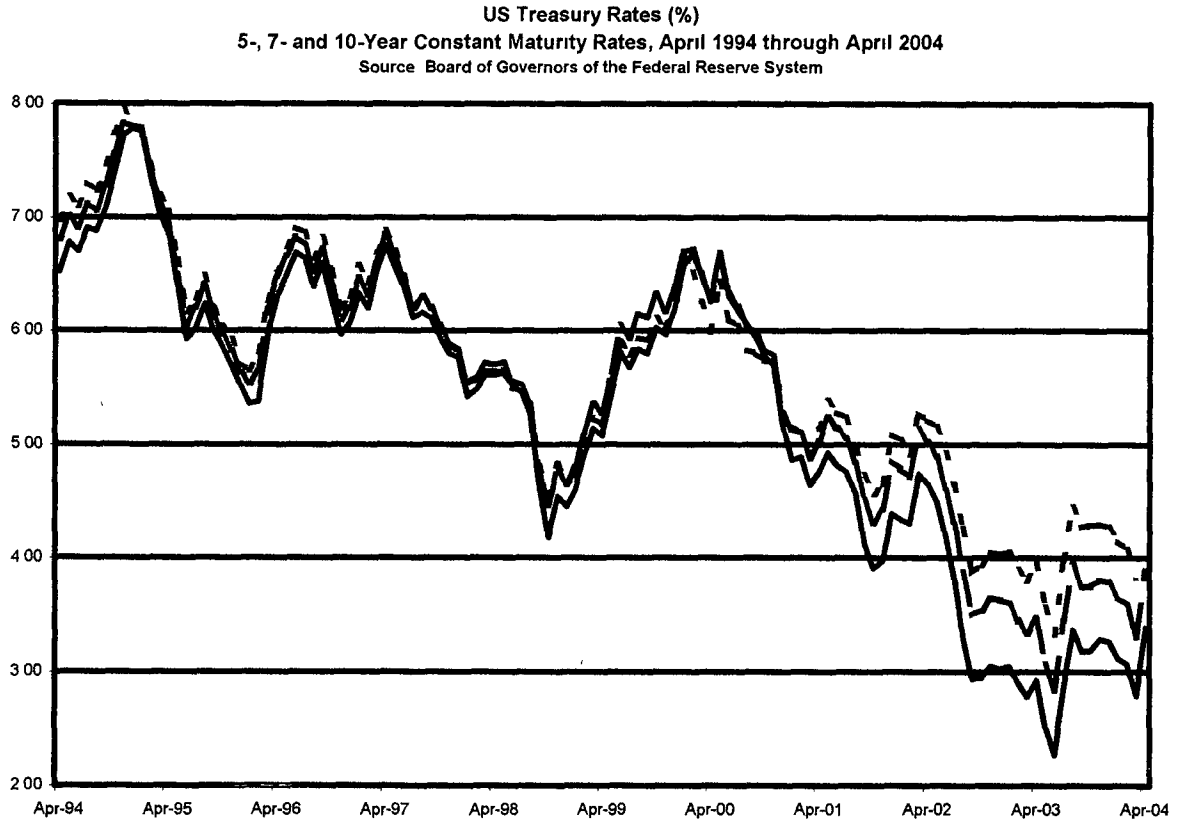
[1] More precisely, the *marginal* investor determines the firm's cost of capital The marginal investor will bid the price of the security up to a point that the investor expects to earn the cost of capital and no less Then, the security is in equilibrium The definition of expected return based on returns on investments of similar risk (the "comparable earnings" standard) also assumes that the alternate security is in equilibrium and the investor does not expect to earn excess profits on that alternate security For example, assume securities A and B are of similar risk and have a 10 percent cost of equity Now assume that security B developed an invention such that it will realize a

historical perspective on interest rates and stock returns and then it focuses on the cost of equity to the electric utility industry

A Historical Perspective on Interest Rates

Q. FIRST, PLEASE PUT CAPITAL COSTS IN PERSPECTIVE. WHAT HAS BEEN THE TREND OF INTEREST RATES OVER THE PAST TEN YEARS OR SO?

A Interest rates have declined significantly over the past ten years and breached the record lows seen in 1993 The chart below graphs intermediate-term[2] U S.



20 percent return to current investors forever *However, 20 percent is not security B's cost of equity, nor is it security A's* The marginal investor will bid up the price of security B's stock (the price will double) until the marginal investor only expects to earn the 10 percent cost of equity in equilibrium on security B The 10 percent equilibrium rate of return is security B's, and security A's, required rate of return

[2] U S Treasury constant-maturity five-, seven-, and ten-year rates published by the Board of Governors of the Federal Reserve System

Treasury rates from April 1994 through April 2004

Q. WHERE ARE INTEREST RATES NOW WITH RESPECT TO HISTORICAL RATES?

A Interest rates are currently low compared to historical rates The graph below shows ten-year U S Treasury constant maturity security yields from April 1953 (the beginning of the data series) through April 2004 You can visually see in the graph that interest rates are near lows over that span of history

10-Year US Treasury Constant Maturity Rates (%)
April 1953 to April 2004
Source: Board of Governors of the Federal Reserve System



About seventy percent of ten-year-maturity U S Treasury constant-maturity rates throughout this historical time period exceed the current 4 73 percent ten-year rate

The Federal Reserve reported that on May 4, 2004, the Federal Open Market Committee voted to keep its target federal funds rate at 1 percent, a 46-year low (*See* http //www stlouisfed org/) Interest rates and capital costs are low by historical standards.

A Historical Perspective on Stock Returns

Q. WHAT HAVE BEEN HISTORICAL NOMINAL RETURNS FOR AVERAGE-RISK SECURITIES?

A The following table reproduces average (arithmetic and geometric) nominal returns for a range of domestic and international stock price indicator series (1972 to 1995)

Annual Percentage Rates of Return for Stock Price Indicator Series: 1972-1995		
Stock Index Series	Arithmetic Average	Geometric Average
Dow Jones Industrial Average	8 91%	7 58%
S&P 500	9 07%	7.79%
AMEX Value Index	12.2%	9 81%
NASDAQ Composite	12 79%	10 67%
Wilshire 5000	9 58%	8 16%
Toronto SE 300 Composite	11 97%	10.68%
Financial Times All-Share	14.24%	9 94%
FAZ	8 61%	6.02%
Nikkei	11 54%	8.76%
Tokyo SE Index	11 78%	8.78%
Morgan Stanley World	9.61%	8.28%
Average	10 94%	8.77%
Source Frank J Reilly, Investment Analysis and Portfolio Management, fifth edition, p 172		

One should keep in mind that these series measure actual returns, not expected returns. However, any request for an allowed ROE above 11 0 percent

exceeds the geometric mean return for **all** of these indices of average-risk securities' returns The average electric utility in my sample is significantly less risky than the average security, as I will later discuss in my capital asset pricing model analysis.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN AN ARITHMETIC AND A GEOMETRIC AVERAGE RATE OF RETURN.

A Let me answer you through an example Let us say that you invested $100 in a stock The first year you made 100 percent return on your money (your stock's value has risen to $200), but the second year you lost 50 percent of your money (alas, your stock's value has fallen back to $100) The arithmetic average is the simple average of 100 percent and -50 percent, or 25 percent [(100% + -50%)/2] The geometric average is a bit more complicated. In this example, you add the number one to each of the annual returns to form two "value relatives," multiply the value relatives together, take the square root, and then subtract the number one

$$\text{Geometric average} = \sqrt{(1+100\%)(1+(-50\%))} - 1$$
$$= 0\%$$

Notice in this case the arithmetic average rate of return is spurious If you invested $100, made 100 percent the next year but then lost 50 percent in the following year, then you would end up with $100, exactly where you started The geometric average correctly indicates that your average rate of return over two years is zero percent. The arithmetic average rate of return would have you believe that, on average, you made 25 percent return per year. The geometric average rate of return is used to express average rates of return over time

Q. WHAT HAS BEEN THE LONG-TERM AVERAGE NOMINAL RETURN TO THE AVERAGE-RISK STOCK SINCE 1926?

A The geometric average return for stocks from 1926 through 2003 was about 0 79 percent per month, or about 10 percent compounded per year.

Q. WHAT HAVE HISTORICAL REAL RETURNS BEEN FOR AVERAGE-RISK SECURITIES?

Wharton School finance professor Jeremy J Siegel, author of the book *Stocks For The Long Run*, found that the average real return on U S equities has been 6 9 percent using 200 years of data from 1802 through 2001.[3] I include pages 11 to 24 of his book on pages 2-12 of Exhibit JST–1 because they discuss a number of issues pertinent to this case, including U S stock return history, international equity returns, and the equity premium. The 6 9 percent real return on stocks has been remarkably stable over time Dr. Siegel writes on pages 12 and 13 of his book,

> "The real return on equities has averaged 6.9 percent per year over the past 200 years... Note the extraordinary stability of the real return on stocks over all major subperiods 7 0 percent per year from 1802-1870, 6 6 percent from 1871 through 1925, and 6 9 percent per year since 1926. Even since World War II, during which all the inflation that the United States has experienced over the past 200 years occurred, the average real rate of return on stocks has been 7.1 percent per year. This is virtually identical to the preceding 125 years, which saw no overall inflation This remarkable stability of long-term real returns is a characteristic of *mean reversion*, a property of a variable to offset its short-term fluctuations so as to produce far more stable long-term returns "

[3] Jeremy J Siegel, *Stocks for the Long Run*, third edition, McGraw-Hill, 2002, p 13

The current expected rate of inflation over the next ten years is approximately 2 7 percent based on U.S Treasury yield data,[4] leading one to conclude that the average-risk security is expected to yield a nominal 9 6 percent rate of return

Q. HAVE OTHER MAJOR INTERNATIONAL MARKETS HAD REAL RETURNS GREATER THAN THE HISTORICAL RETURNS IN THE U.S. EQUITIES MARKETS INDICATING A HIGHER MARKET RETURN IF ONE WERE TO INCLUDE INTERNATIONAL EQUITIES?

A. No, in fact just the opposite seems to be the case Dr Siegel calculated the following compound annual real equity returns for Germany, the United Kingdom, and Japan·[5]

Compound Annual Real Equity Returns (1926-2001)			
US	Germany	U K.	Japan
7 00%	6 44%	6 01%	2 93%

Therefore, these international equities' real returns did not exceed the 7 0 percent real return on U S equities over the 1926-2001 period and including them would not result in a higher assessment of equities' real expected returns

Similar conclusions to Dr. Siegel's were reached by Elroy Dimson, Paul Marsh and Mike Staunton in their book *Triumph of the Optimists, 101 Years of Global Investment Returns* They found that for the 101-year period 1900 to 2000

[4] Estimated as the link relative difference between 10-year U S Treasury yield (4 73%) and a ten-year inflation-indexed Treasury security (2 0%) quoted in the May 26, 2004, of *The Wall Street Journal*
[5] Jeremy J Siegel, *Stocks for the Long Run*, third edition, McGraw-Hill, 2002, p 19

U S. equities returned 10 1 percent per annum in nominal terms and 6 7 percent in real terms [6]

Electric Utility Risk and Its Relationship to an Average-Risk Security

Q. ARE ELECTRIC UTILITY COMPANIES MORE RISKY OR LESS RISKY THAN THE AVERAGE-RISK SECURITY?

A Electric utility companies are significantly less risky than the average-risk security. I provide quantitative evidence to support my assertion in the capital asset pricing model section of my testimony. the average risk security has a capital asset pricing model beta of 1 0, while the average electric utility from my sample has a *Value Line* beta of 72, which is 28 percent less risky than the average-risk security

Q. WHAT DOES THE EVIDENCE THAT AN ELECTRIC UTILITY IS SIGNIFICANTLY LESS RISKY THAN THE AVERAGE-RISK SECURITY IMPLY ABOUT EXPECTED RETURNS ON ELECTRIC UTILITY EQUITY INVESTMENTS?

A The fact that an electric utility is less risky than the average-risk security implies that an electric utility's cost of equity and returns are expected to be significantly lower than the average-risk security

[6] Elroy Dimson, Paul Marsh and Mike Staunton, *Triumph of the Optimists, 101 Years of Global Investment Returns*, Princeton University Press (2002) pages46 and 47

Cost of Equity to the Electric Utility Industry

Q. WHAT METHODS DID YOU USE TO ESTIMATE THE COST OF EQUITY CAPITAL TO AN AVERAGE ELECTRIC UTILITY AND AVISTA CORPORATION?

A. I used the discounted cash flow (DCF) model and the capital asset pricing model (CAPM) These two models are widely used for estimating the required return on equity I applied my DCF and CAPM analyses to a sample of electric utility companies I used a sample in order to limit estimation error that might be involved with applying the models to Avista exclusively.

Sample Selection

Q. WHAT SAMPLE OF COMPANIES DID YOU USE AND HOW DID YOU SELECT THEM?

A I selected thirty-two electric utilities amongst all the electric utilities covered by *The Value Line Investment Survey* (*Value Line*). I eliminated companies for whom *Value Line* did not report comparable data through at least 1998 or had skipped a dividend or had negative earnings since 1998, companies for whom *Value Line* did not forecast dividends, and companies that did not appear to be primarily domestic integrated electric utility companies.

DCF Model Analysis

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW MODEL.

A The DCF model[7] is based upon the premise that a company's stock price is equal to the present value of all future dividends expected to be received by a share of stock. The expected dividends are discounted by the company's cost of common equity

Mathematically, the DCF model for the cost of equity is represented by the following equation

$$(1) \quad P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \ldots \frac{D_n}{(1+k)^n}$$

Equation (1) is quite simple and says that the current price of a stock (P_0) is equal to the sum of expected future dividends (D_1 through D_n) discounted into present value terms at the company's cost of equity (k). D_1 is the dividend expected one year hence, D_2 is the dividend expected two years hence, etc Dividends can be related to each other by growth rates. For example, D_2 is equal to D_1 times a growth factor, D_3 is equal to D_2 times a growth factor, D_4 is equal to D_3 times a growth factor, etc In this way, each dividend can be related to the dividend before it through a growth factor If we already know a stock's price and can estimate forecasted dividends (or dividend growth rates) then we can use equation (1) to give us the cost of equity, k, through a calculation called an "internal rate of

[7] A full derivation is included in the appendix to this testimony The DCF model was first formalized in John Burr William's book *The Theory of Investment Value* (Cambridge Harvard University Press, 1938) The concept of discounting dividends to value a stock dates back to at least 1930 and Robert F Wiese's article "Investment for True Values " *Barrons*, September 8, 1930 p 5 The DCF model was resurrected by Myron Gordon and E Shapiro who used it to solve for the cost of equity in their article, "Capital Equipment Analysis Required Rate of Profit," *Management Science* 102 (October 1956) Myron Gordon expanded the DCF model in the early 1960's, employing the model mainly as a method for estimating the cost of capital He later published his work in *The Cost of Capital to a Public Utility* (Michigan MSU Public Utilities Studies, 1974) Myron Gordon is considered the father of modern DCF analysis

return" calculation That calculation essentially finds the cost of equity that equates the present value of dividends to the current stock price

Q. HOW DID YOU APPLY THE DCF MODEL?

A I applied the DCF model using the multi-stage growth model The multi-stage growth model is generally superior to the constant-growth DCF model because it allows for flexibility in dividend growth rates This flexibility is impossible in the constant-growth model The extra computing cost associated with implementing the multi-stage model is minimal compared to the model's benefits The multi-stage model cannot be inferior to the constant-growth DCF model, therefore one should use the multi-stage model if possible I applied the model to each of the thirty-two companies in the sample and I averaged the costs of equity derived from each of the companies My multi-stage growth model included *Value Line* dividends expected over the next twelve months (the first stage), *Value Line*'s dividend forecasts and their implied dividend growth rates for 2004 to 2007-2009 (the near-term stage) and a series of forecasted dividends growing at a long-term growth rate (the long-term stage) The first input, however, is the current stock price.

Q. WHAT DID YOU USE FOR THE CURRENT STOCK PRICE, P_0?

A I used closing stock prices for the current stock price, P_0, from the May 26, 2004, issue of *The Wall Street Journal* for May 25, 2004, prices. The most current spot prices are the correct prices to use for P_0 because current spot prices include all current and past information.

The First Stage

Q. WHAT DID YOU USE FOR THE FORECAST DIVIDEND, D_1, FOR THE FIRST STAGE?

A I obtained forecasts of D_1 (the expected dividend per share over the next twelve months) directly from the May 21, 2004, "Summary and Index" to *Value Line* (Est'd Div'd next 12 mos) This gave me a direct forecast of D_1, or dividends expected over the twelve months My sample's average dividend yield is 4 55 percent, shown on page 13 of Exhibit JST–1

The Second Stage

Q. WHAT DID YOU USE FOR THE FORECAST DIVIDENDS FOR THE SECOND OR NEAR-TERM STAGE?

A I grew the expected dividend per share over the next twelve months (D_1) by *Value Line*'s implied dividend growth rates for the period 2004 to 2007-2009 for three years The multi-stage model allows one to use *Value Line*'s (interpolated) dividend forecasts for each company to be included in the DCF and it is a superior method to using a constant growth rate across all companies because one is using data more efficiently

The Third Stage

Q. WHAT DID YOU USE FOR THE FORECAST DIVIDENDS FOR THE THIRD OR FINAL STAGE OF GROWTH?

A I took the last dividend for each sample company in my near-term stage and grew that dividend at a long-term rate. My estimate of dividend growth in the long-term stage is 3 percent to 5 percent I estimated the long-term dividend growth

component after reviewing a large amount of historical and forecast electric utility industry and macroeconomic data that can be helpful in estimating long-term dividend growth, and based on my previous experience in estimating dividend growth for electric utilities My sample's average dividend actually declined between 1998 and 2003 Earnings and book value have both grown, on average, 1 9 and 3 6 percent, respectively *Value Line*'s estimated "'00-'02/'01-'03 to '07-'09" annual rate of dividend growth for my sample of companies averages 1 6 percent The same estimates for earnings and book value growth are 3 3 and 4.3 percent, respectively Sample br, or intrinsic growth, has averaged 3 4 percent for the period 1998 through 2003

Q. WHAT BROAD MACROECONOMIC DATA MIGHT YOU USE TO GAUGE INVESTORS' EXPECTATIONS OF DIVIDEND GROWTH?

A. One might use economic growth and share growth. Dividends per share is a ratio of total dividend payments divided by total shares outstanding Therefore, dividend per share growth might be modeled by estimating the expected growth in total dividends (in the numerator) minus the expected growth in shares outstanding (in the denominator). To model total dividend payment growth, one might use national economic growth because electric utility dividends cannot exceed electric industry earnings over the long term and electric utility earnings cannot exceed national domestic economic growth in the long term Real U.S gross domestic product (GDP) growth has been 3 26 percent per year from January 1953 through January 2004[8] and current inflation is expected to be 2 7 percent based on my earlier calculation, resulting in nominal growth of 6 0

percent (3.26% + 2 7%) My sample's outstandıng shares grew 2 8 percent between 1998 and 2003 and are expected to grow .92 percent from 2003 through 2007-2009 Therefore, subtractıng per share growth from nomınal GDP growth results ın a "dıvidend"-per-share growth rate range of 3 2 percent (6.0% - 2.8%) to 5 1 percent (6 0% - 92%)

Q. WHAT BROAD MACROECONOMIC DATA SPECIFIC TO DIVIDENDS MIGHT YOU USE TO GAUGE INVESTORS' EXPECTATIONS OF DIVIDEND GROWTH?

A Jeremy Sıegel, ın hıs book *Stocks For The Long Run* (thırd edıtıon, page 94) reports that real annual per share dıvidend growth has been 1 09 percent for the perıod 1871 through 2001 ın the followıng table

Period	Real GDP Growth	Real Per-Share Earnings Growth	Real Per-Share Dividend Growth
1871-2001	3 91%	1 25%	1 09%
1871-1945	4 51%	0.66%	0.74%
1946-2001	3.11%	2 05%	1 56%

Addıng an expected ınflatıon rate of 2 7 percent to a real 1 09 percent real dıvidend growth rate results ın about 3 8 percent expected dıvidend growth (1 09% + 2 7%) Relyıng on the post-war 1.56 percent real per share dıvidend growth rate results ın about 4 3 percent annual growth (1.56% + 2.7%). These data suggest about a 4 percent dıvidend per share growth rate.

Q. WHAT IS THE MARKET-TO-BOOK RATIO FOR YOUR SAMPLE OF COMPANIES AND WHAT DOES IT IMPLY?

[8] Source U S Department of Commerce Bureau of Economic Analysis

A The market-to-book ratio for my sample of companies is 1 62. A market-to-book ratio greater than 1 0 indicates that my sample of utilities is expected to earn accounting ROEs significantly greater than the utilities' costs of equity I prove this relationship in the appendix Over earnings can result from many factors, including commissions authorizing ROEs in excess of the costs of equity. The observation that the electric utilities are expected to over earn casts doubt on using expected earnings or earnings growth to estimate long-term dividend per share growth. Therefore, earnings forecasts should not be used as a proxy for the cost of equity because they over estimate the cost of equity

The market-to-book ratio for Avista is 1 07, indicating that is expected to earn accounting returns close to its cost of equity. *Value Line* forecasts Avista's accounting return on equity to be 8 percent in the 2007-2009 time frame.

Q. WHAT ARE YOUR AVERAGE COST OF EQUITY ESTIMATES FOR YOUR SAMPLE COMPANIES USING THE MULTI-STAGE DCF MODEL AND YOUR RANGE OF LONG-TERM DIVIDEND GROWTH RATES?

A My estimates are summarized in the table below·

Multi-Stage DCF Estimates	
3% long-term stage growth rate	7.5%
4% long-term stage growth rate	8.4%
5% long-term stage growth	9 2%
Average.	8.4%

I include the summary tables supporting my multi-stage DCF estimates on pages 14-16 of Exhibit JST–1

allows investors to reduce their level of risk exposure for any given level of expected return The risk that is left is called systematic risk Systematic risk measures the extent to which a security's returns are correlated with returns in the general market of risky assets. In other words, the insight of the CAPM is that a firm's risk is not simply measured by the variability (standard deviation) of its own returns, but the extent to which its returns are related to market portfolio returns The CAPM[11] is summarized in the following formula,

$$(2) \qquad E_{t-1}[R_{i,t}] = R_{f,t} + \beta_{i,t}(E_{t-1}[R_{M,t}] - R_{f,t})$$

Q. WHAT DO THESE VARIABLES REPRESENT?

A $E_{t-1}[R_{i,t}]$ is the investors' expected return on security i over the investment horizon t and it is conceptually equivalent to the k term in the DCF model [12] This term represents the cost of equity to Avista Corporation that we are attempting to estimate

$R_{f,t}$ is the return on the risk-free asset during time period t. A default-free U S Treasury security is generally used as the proxy for the risk-free asset

$\beta_{i,t}$ is an index of security i's systematic risk, called beta, expected over the investment horizon t

$E_{t-1}[R_{M,t}] - R_{f,t}$ is the expected market risk premium The market risk premium entices investors to invest in the market portfolio of risky securities

[10] More precisely, assuming that the variance of returns of companies A and B are the same, the portfolio of them together has the variance $\sigma^2(A) + \sigma^2(B) + 2\rho(A,B)\sigma(A)\sigma(B)$ If $\rho(A,B) = -1$ (the securities' returns are perfectly negatively correlated), and $\sigma(A) = \sigma(B)$,then the portfolio variance equals 0

[11] The CAPM's derivation can be found in many finance textbooks, including Ross and Westerfiled's book *Corporate Finance* (St Louis Time Mirror/Mosby College Publishing, 1988)

instead of the lower-yielding risk-free asset The premium for investing in the market portfolio of risky assets is called the market risk premium

Q. WHAT DOES THE CAPM FORMULA SAY?

A The CAPM formula, equation (2), is intuitive and simple The formula says that investors expect a yield on a company's risky security to equal the risk-free rate plus a risk premium That company-specific premium is determined by multiplying beta, the measure of risk, by the overall market risk premium

Q. WHAT DOES BETA MEASURE?

A Beta measures the systematic risk of a company and it can be thought of as an index of relative riskiness Systematic risk is the only form of risk that is relevant to estimating a company's cost of equity because all other risk can be eliminated through diversification (that is, buying a stock along with a portfolio of other stocks) as I discussed earlier Systematic risk can be thought of more concretely as an index reporting the extent to which a security's returns are correlated with overall market returns (and the general economy). The average-risk security has a beta of 1.0 by definition and its returns are perfectly correlated with the market's returns. A more risky security has a beta greater than 1 0, and a less risky security has a beta less than 1.0 Public utilities generally have betas below 1.0 and are considered much less risky than the average firm.

Q. WHAT INFORMATION IS NEEDED TO APPLY THE CAPM?

A We need estimates of the following over an assumed investment horizon of "t" years.

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[12] The two methods can produce different results, in principle, as articulated by M J Gordon and L I Gould in their article "Comparison of the DCF and HPR Measures of the Yield on Common Shares," *Financial Management* (Winter 1984)

The risk-free rate (R_f);

Beta (β_i), and,

The market risk premium ($E[R_m] - R_f$)

Q. HOW DID YOU APPLY THE CAPM FORMULA?

A I applied the CAPM formula by first assuming that investors have an intermediate-term investment horizon, which I defined as between five and ten years long An investment horizon is a period over which investors expect to hold securities when they first purchase those securities The investment horizon is more formally called a holding period in financial economics.

Q. WHY DO YOU NEED TO MAKE AN EXPLICIT ASSUMPTION ABOUT INVESTORS' HOLDING PERIODS WHEN APPLYING THE CAPM?

A The CAPM is known as a holding period model One makes estimates of the risk-free rate, beta, and the market risk premium over some particular holding period to estimate the cost of equity during that period The holding period length corresponds to the subscript "t" in equation (2)

Q. WHY DID YOU CHOOSE AN INTERMEDIATE-TERM HOLDING PERIOD?

A I chose an intermediate-term holding period in conjunction with using intermediate-term U S. Treasury securities (Treasuries) and based on my assumption that investors' expected investment horizons are intermediate in length Intermediate-term Treasury yields are the most appropriate yields to use for rate making because short-term Treasuries (T-bills) can be too volatile for the rate-making process, though academic CAPM studies use short-term Treasuries. Long-term Treasuries (T-bonds) contain a "price risk" premium that should be

estimated and extracted before use in the CAPM [13] I have never seen long-term Treasuries used in any academic study of the CAPM Thirty-year Treasuries weren't even sold until fifteen years or so after the CAPM's publication and the U S. Treasury has suspended its sales of the thirty-year bond. The U.S Treasury no longer publishes a rate for maturities over 20 years The intermediate term also corresponds most closely to the typical period during which utility rates are in effect and the period during which shareholders would require compensation Authorized rates of return are not set as frequently as monthly, or as infrequently as every thirty years, but somewhere in between the two extremes After establishing my holding period, I estimated the risk-free rate

Risk-Free Rate

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE AND HOW DID YOU ESTIMATE IT?

A I estimated the risk-free rate to be 4 3 percent. My estimate is based upon an average of intermediate-term U S Treasury securities' spot rates published in *The Wall Street Journal* Published rates as determined by the capital markets are objective, verifiable, and readily available, as opposed to rates published by a forecasting service which are not necessarily objective, and are certainly not verifiable or readily available. I averaged the yields-to-maturity of three intermediate-term (five-, seven- and ten-year) U.S Treasury securities quoted in the May 26, 2004, edition of *The Wall Street Journal* [14] The page on which I

[13] Ibbotson Associates' *SBBI 2004 Yearbook*, page 175, estimates this long-term bond premium at 1 6 percent

[14] The rates were 3 88%, 4 40%, and 4 73%

relied is included as page 17 of Exhibit JST–1 Page 18 of Exhibit JST–1 also shows a variety of interest rates Notice that the Discount Rate, a key rate on the economy, is quoted at 2 00 percent and the Prime Rate is 4 00 percent Interest rates and capital costs are low and investors can reasonably expect low authorized ROEs based on these low interest rates

Beta

Q. WHAT IS YOUR ESTIMATE OF BETA?

A I provide three beta estimates (55, 59, and .72) for the Commission's consideration. They are derived from *Value Line* My better beta estimates, as I discuss below, are the average *Value Line* betas for my sample of companies after correcting for a *Value Line* procedure that tends to bias utility betas upwards.

Q. ARE *VALUE LINE* BETAS THE BEST BETAS ON WHICH TO RELY FOR ESTIMATING THE COST OF EQUITY FOR UTILITIES?

A No. Statistical evidence I reviewed indicates that other types of betas better represent actual market returns than *Value Line*-type betas which are ordinary least squares betas These other betas include Fisher-Kamin betas and Wells (autoregressive conditional heteroskedasticity-corrected) betas However, these other betas are not currently available to me and so I relied on the best information I had available I made improvements to the reported *Value Line* betas by "de-adjusting" them somewhat. *Value Line* betas are adjusted toward 1 0 (actually toward 1 06 implicitly) under the presumption that betas naturally move toward 1.0 over time The problem for estimating electric utility betas is that electric utility betas are less than 1.0 and they haven't historically shown a

systematic tendency over time to move toward 1 0 Therefore, *Value Line*'s procedure upwardly biases beta estimates for electric utilities

Q. WHAT IS *VALUE LINE*'S ADJUSTMENT PROCEDURE AND HOW DID YOU IMPROVE *VALUE LINE*'S REPORTED BETAS BY DE-ADJUSTING THEM?

A *Value Line*'s adjustment formula is,

Adjusted V-L beta = 35 + 67*(unadjusted beta)

The average beta for my sample of electric utilities is 72 Reversing the formula to de-adjust a .72 beta results in a 55 unadjusted (or raw) average beta

Unadjusted V-L beta. 55 = (72 - 35)/.67

I also provide a beta re-adjusted to 1 0, but only by 10 percent

Re-adjusted beta **.59** = 10%x(1.0) + 90%x(55)

I report CAPM results based on these three betas· 55, .59, and 72 My sample companies' 2003 capital structures , *Value Line* betas, and my adjustments to them are shown on page 19 of Exhibit JST–1

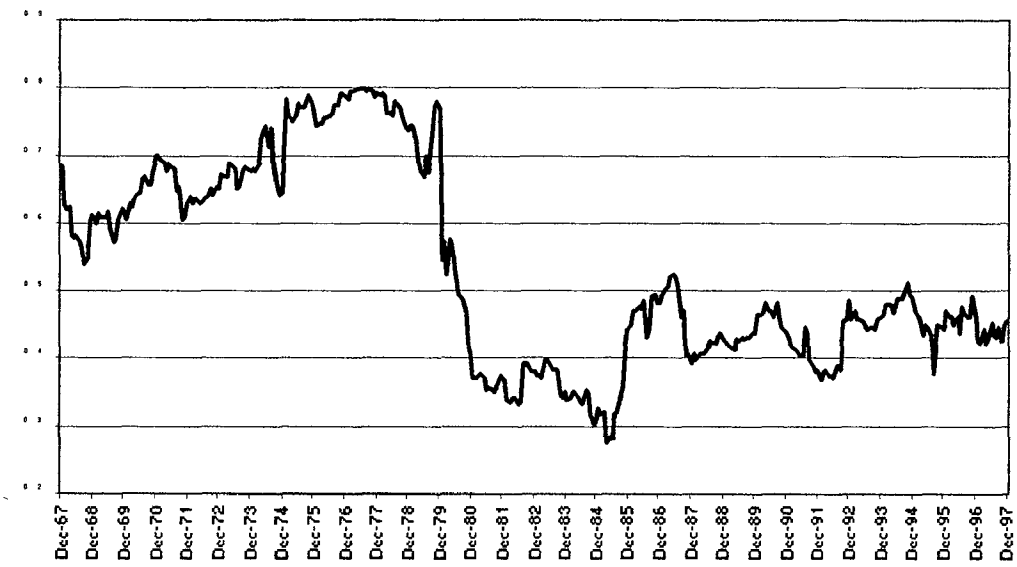
Q. HAVE ELECTRIC UTILITY BETAS SYSTEMATICALLY RISEN TOWARD 1.0 OVER TIME?

A. No, they have not systematically risen toward 1.0, at least not since 1967

Q. ON WHAT DO YOU BASE YOUR CONCLUSION?

A I performed a study examining the monthly sample average beta[15] of 74 electric utilities from 1967 to 1997. The results of my study are graphed below. CAPM beta risk has clearly fallen since the mid 1960s and 1970s The chart below depicts the history of the average electric utility beta over time.

Electric Utility OLS Betas Over Time
December 1967 through December 1997



The graph would have looked like a ramp heading upward to 1 0 if electric utility betas had been systematically rising toward 1 0 The last beta on the graph is .46, which is only 0 9 less than the current .55 raw *Value Line* beta that I discussed above Therefore, both the chart and recent evidence indicate that electric utility betas have not tended to systematically rise toward 1 0

Q. WHY DO YOU CALCULATE A *VALUE LINE* BETA ADJUSTED TOWARD 1.0 BY 10 PERCENT?

A. I report a "re-adjusted" *Value Line* beta adjusted to 1 0 by 10 percent based on statistical studies of ordinary least squares betas and their forecast ability. The studies found that if an ordinary least squares beta is to be used and if it must be adjusted toward 1 0 then the best adjustment is 10 percent, on average

[15] 60-month ordinary least squares

Q. WHAT IS YOUR RANGE OF MARKET RISK PREMIUM ESTIMATES?

A My range of estimates is 6 1 percent to 7 8 percent

Q. HOW DID YOU CALCULATE YOUR MARKET RISK PREMIUM RANGE?

A My market risk premium range is my best estimate of the historical market risk premium (6 1 percent) and my current market risk premium (7 8 percent) If one consistently uses the long-run average market risk premium to estimate the expected market risk premium, one should, on average, be correct Dr Siegel, cited above, found that U S equities' real returns were quite stable over long periods and averaged 6.9 percent historically At any one time the current market risk premium might be greater or less than the historical average Estimating the current market risk premium presents more difficulty but it is useful information if it can be estimated with some confidence

Q. PLEASE DESCRIBE WHAT AN INTERMEDIATE-TERM MARKET RISK PREMIUM IS AND HOW YOU ESTIMATED IT.

A The expected market risk premium for an investor with an intermediate-term holding period is the difference between expected compounded returns on the market portfolio and the compounded returns on the risk-free asset over an intermediate period For example, the historical market risk premium is the difference in returns between an investor's two accounts one invested in the stock market and the other invested in U S. Treasury securities, both over an intermediate period The difference is then annualized

I estimated the historical market risk premium by the following steps [16]

1 I used the Center for Research in Securities Prices' 1926-1999 NYSE/AMEX/NASDAQ returns as a proxy for the theoretical market portfolio returns I updated market returns through 2003 using Ibbotson Associates' *Stocks, Bonds, Bills, and Inflation 2004 Yearbook* (large company stock total return index [S&P 500])

2 I used 1926-2003 data on intermediate-term U.S Treasury securities rates from Ibbotson Associates' *Stocks, Bonds, Bills, and Inflation 2004 Yearbook* to estimate risk-free rates over that period I used two different series from the *Yearbook* yields (ex ante rates) and total returns (ex post rates) I performed separate analyses using each of the series

3 I separated my 1926 to 2003 data into holding periods of five to ten years each such that all my data were used once, but only once (this method is technically called the simple unbiased estimator). I then calculated the average rate-of-return difference between holding the market portfolio and holding the risk-free rate over the intermediate term and then I annualized the difference

My estimates are shown below.

Historical Market Risk Premium Estimates	
Ex Ante Risk-Free Rates	
72-month holding period	6 10%
78-month holding period	6.70%
104-month holding period	6.30%
Average	6 40%
Ex Post Risk-Free Rates	
72-month holding period	5 70%
78-month holding period	6 30%
104-month holding period	5.50%
Average	5 80%
Average of two midpoints	6 10%
Estimates rounded to three decimal places	

The average of my midpoint estimates is 6.1 percent

[16] My method is substantially the same as published by Russell J Fuller and Kent A Hickman in their article, "A Note on Estimating the Historical Risk Premium" *Financial Practice and Education* (Fall/Winter 1991) pp 45-48

Q. HOW DID YOU ESTIMATE THE CURRENT MARKET RISK PREMIUM?

A I estimated the current market risk premium by essentially the same method that I used to calculate the historical market risk premium but I applied the method to forecasted data For the forecast return on the market, I used *Value Line*'s forecasted dividend yield and capital appreciation for all 1,700 stocks it covers three to five years hence, or four years on average *Value Line* forecasts 1 7 percent dividend yield over the next twelve months and 50 percent price appreciation three to five years hence. This gave me a total return forecast of about 11 9 percent per year for this broad basket of *Value Line* stocks over the next four years. The rate on a four-year U.S Treasury note is currently 3 57 percent [17] The implied annual expected market risk premium from these figures is 7.8 percent[18] (rounded to three decimal places) This calculation assumes a four-year holding period which is less than my five- to ten-year holding period assumption and it would lead to a biased-upward market risk premium estimate (shorter holding period assumptions tend to result in higher market risk premium estimates) However, I do not expect the bias to be significant enough to outweigh the benefit of the calculation

Q. WHAT ARE YOUR CAPM COST OF EQUITY ESTIMATES?

A My CAPM estimates, based on my three beta estimates and my historical and current market risk premium estimates, follow.

[17] May 26, 2004, edition of *The Wall Street Journal*

[18] The calculation is not the simple difference of the annualized market return and the annual risk-free rate The nominal annual rate is calculated from the ratio of the two value relatives, one for the market basket and the other for the investment in the risk-free rate, and then annualized (annualized nominal monthly)

CAPM Estimates							
	$E(R_i)$	**=**	**Risk-Free Rate**	**+**	**Beta**	*****	**MRP**
Historical MRP	7 70%	=	4 30%	+	0 55	*	6 1%
	7 90%	=	4 30%	+	0 59	*	6 1%
	8 70%	=	4 30%	+	0 72	*	6 1%
Current MRP	8 60%	=	4 30%	+	0 55	*	7.8%
	8 90%	=	4.30%	+	0 59	*	7 8%
	9.90%	=	4 30%	+	0 72	*	7 8%
Average	**8.60%**						
Cost of equity estimates rounded to three decimal places							

Cost of Equity Estimates to The Electric Utility Industry

Q. PLEASE SUMMARIZE YOUR COST OF EQUITY RANGE AND POINT ESTIMATES FOR THE ELECTRIC UTILITY INDUSTRY AND EXPLAIN HOW YOUR RANGE WAS CHOSEN.

A I estimate that the cost of equity to the electric utility industry is within a range of 7.5 percent to 9.9 percent, based on my estimates shown in the table below.

Summary of Cost of Equity Estimates To The Electric Utility Industry	
DCF low	7 50%
DCF midpoint	8 40%
DCF high	9 20%
CAPM low	7 70%
CAPM midpoint	8 60%
CAPM high	9 90%
Electric industry cost of equity:	**8.50%**

My point estimate is 8 5 percent, the average of my DCF and CAPM midpoints.

Cost of Equity Estimates and ROE Recommendation For Avista Corp.

Q. SHOULD YOU ADJUST YOUR COST OF EQUITY FROM THE ELECTRIC UTILITY SAMPLE FOR DIFFERENCES IN CAPITAL STRUCTURES BETWEEN THE SAMPLE AND AVISTA CORP?

A Yes One should consider differences in capital structures between a sample and the company to which the estimate is applied (a higher percentage of debt in a capital structure implies a higher cost of equity because of increased financial risk) This adjustment is intended to be consistent with the CAPM. However, the percentage of common equity in Avista's filed capital structure (44 3 percent) is not significantly different from my sample's average level of common equity (45 percent) Therefore, I did not make any adjustment and I used my sample average cost of equity as my estimate of Avista's cost of equity My estimate of Avista's cost of equity is 8.5 percent

Recommended Rate of Return

Q. WHAT RATE OF RETURN (ROR) DO YOU RECOMMEND?

A. I recommend an 8 49 percent ROR. I also present two other ROR calculations based on my high and low cost of equity estimates. The three ROR calculations are shown on page 1 of Exhibit JST–1

Q. IS YOUR ROR EXPECTED TO MAINTAIN THE COMPANY'S FINANCIAL INTEGRITY?

A Yes The interest coverage ratio implied by my recommended 8.49 percent ROR is 2 69, which can be expected to maintain or enhance the Company's financial integrity Standard and Poor's *Corporate Ratings Criteria* (page 50) reports that

the median interest coverage ratio for utilities rated BBB was 2 1 in the 2000-2002 period Avista Corporation's current rating for senior secured debt is BBB- Neither of my other options results in a coverage ratio less than 2 1 Standard and Poor's *Corporate Ratings Criteria* reports that the median ROE for BBB-rated utilities was 7 4 percent (my recommendation is higher, which is better for the Company) and total debt to total capital was 62.6 percent (Avista's filed capital structure has 55 7 percent debt and preferred stock, which is lower and better for the Company). Therefore, the end result of my recommendation should allow Avista to maintain its financial integrity, earn returns comparable to returns of companies of similar risk, and attract capital

Examination of Mr. Malquist's 11.5% Return on Equity Recommendation

Q. ON WHAT DOES MR. MALQUIST BASE HIS 11.5 PERCENT RETURN ON EQUITY RECOMMENDATION?

A Mr Malquist bases his recommendation on his own personal belief that "the 11.5% provides a reasonable balance of the competing objectives of regaining financial health within a reasonable period of time, and the impacts that increased rates have on our customers " (*See* Direct Testimony of Malyn Malquist, page 22 at 3 to 6.) He also believes that a return on equity greater than 11 5% is supported and warranted He provides no financial analysis or cost of equity calculations to support his recommendation

Q. SHOULD THE COMMISSION ADOPT AN 11.5 PERCENT ROE BASED ON MR. MALQUIST'S PERSONAL BELIEF?

A. No. The Commission should not adopt an 11.5 percent ROE based on Mr. Malquist's personal beliefs and assertions.

Examination of Dr. Avera's Cost of Equity Analysis

Q. PLEASE SUMMARIZE DR. AVERA'S COST OF EQUITY ANALYSIS.

A. Dr. Avera performed a constant-growth DCF on a sample of eight "western" electric utilities, an allowed ROE premium analysis on an undefined number of companies, a realized risk premium on an undefined number of companies, and a CAPM on his electric utility sample. His range of estimates from these methods is 10.2 percent to 11.7 percent. He adds 0.2 percentage points to his cost of equity estimates to account for flotation costs. I address his cost of equity analyses in turn, and then I address the inappropriateness of his increasing a cost of equity for flotation costs and for a unique risk adder based on bond yields.

Q. DR. AVERA SEEMS TO PORTRAY A RATHER GLOOMY OUTLOOK FOR THE ELECTRIC UTILITY INDUSTRY. DO YOU SHARE HIS PESSIMISM?

A. I do not share his pessimism. On page 15 beginning at line 3 of his direct testimony he states,

> "Combined with a stagnant economy and global uncertainties, the dramatic upward shift in investors' risk perceptions and the weakened financial picture of most industry participants, have combined to produce a severe liquidity crunch in the electric power industry."

His view seems to be supported by reports from 2002 and early 2003.

However, a more recent report by Fitch Ratings, titled *Fitch 2004 Outlook: U.S. Utilities and Merchant Energy Companies Both Stabilize* dated December 15, 2003, says,

> "Although the Outlook for the regulated and unregulated sectors is stable in both cases, this masks the divergent paths both segments have taken While the investor-owned utilities (IOUs) either maintained creditworthiness or are well on their way to recovery, the merchant or competitive energy sector will need much more time (and consistent favorable developments) to recover "

I include Fitch's synopsis of its report as pages 20-21 of Exhibit JST–1 I do not share Dr Avera's pessimism but look for financial improvements to IOUs in 2004 and beyond

Q. IS HIS SAMPLE OF EIGHT WESTERN ELECTRIC UTILITIES APPROPRIATE?

A. I find that his sample is overly restrictive and that useful information on the risk of owning shares in an electric utility can be gained from companies in addition to those defined by *Value Line* as operating in the West (his sample universe) A small sample results in less efficient estimates and in which one should have less confidence. For example, in calculating the dividend yield in the DCF model, a larger sample allows for random daily fluctuations in spot stock prices to even themselves out, resulting in a more efficient estimator. An eight-company sample is less reliable than a thirty two-company sample, all else being equal

I am also concerned that Dr Avera's sample includes Sempra Energy that has divested its generation, according to *Value Line*, and Xcel Energy, Inc that operates primarily in mid-western states and is emerging from its discontinued non-regulated NRG operations resulting in accelerated dividend growth

Furthermore, those earnings growth forecasts are near term (not indefinite) in length and earnings growth forecasts are widely known to be overly optimistic. The average dividend growth rate for his sample companies for the ten years 1994 through 2003 is close to zero (0.219 percent). (*See* page 22 of Exhibit JST–1 for this calculation) Dr. Avera's assumption that his companies will suddenly and forever increase their dividends by 6 percent per year forever after 2004 seems to be tremendously optimistic to the point of incredible A six percent annual growth rate would exceed the historical dividend per share growth rate of the whole economy, according to evidence I presented earlier

Q. WHAT ARE *VALUE LINE*'S DIVIDEND GROWTH PROJECTIONS FOR DR. AVERA'S SAMPLE COMPANIES?

A. *Value Line* publishes dividend forecasts for 2004, 2005, and the 2007-2009 period The implied dividend growth rate for his sample is 3 35 percent for 2004 to 2007-2009 and 3 35 percent for the 2005 to 2007-2009 period (*See* page 23 of Exhibit JST–1 for these calculations) Therefore, one cannot conclude that investors reasonably expect an average annual 6 percent dividend growth in the near future (through 2009) much less into infinity

Q. IF DR. AVERA'S DATA SUPPORTED A 3.0 PERCENT TO 5.0 PERCENT RANGE WHAT WOULD BE HIS DCF ESTIMATES?

A Dr. Avera's cost of equity estimates would be 7.2 percent (4 2% + 3 0%) to 9 2 percent (4 2% + 5.0%) using a 3 to 5 percent growth rate range In other words, a more reasonable interpretation of his data would lead to results near my range of estimates.

Dr. Avera's Allowed ROE Premium Analysis

Q. WHAT IS DR. AVERA'S ALLOWED ROE APPROACH AND IS IT AN ACCEPTABLE APPROACH TO USE IN THIS PROCEEDING?

A. Dr Avera's allowed ROE approach compares annual average authorized ROEs for the years 1974 through 2002 with the yield on Moody's annual average public utility bond yield This approach is frought with problems, from theoretical to statistical [19] The fatal flaw of the approach is that the Idaho Public Utilities Commission is in no way able to determine what these allowed ROEs actually represent, what companies are used in the analysis, what data underlie the ROEs, to what capital structures they were applied, what risks the electric utility industry was facing at the time of the decisions, or what methods were used to arrive at them. For example, how many of the allowed ROEs in Dr. Avera's sample already include a flotation cost adjustment to which Dr Avera would add a second adjustment in this proceeding? Other adjustments might also infect the allowed ROE such as the market pressure adjustment that utilities have sought, or an upward bias from applying the quarterly DCF model, which utilities have sought, or use of the "comparable earnings method," an inferior approach to estimate a cost of equity Moreover, since market-to-book ratios have been above 1 0 for most of the years I have been performing electric utility cost of equity analysis, I conclude that allowed ROEs have, on average, been too high according

[19] Dr Avera's regression includes the average public utility bond yield on both sides of his equation Therefore, his "independent" variable is not truly independent Even if there were no relationship between allowed ROEs and the average public utility bond yield, a regression of the premium of allowed ROEs above the average public utility bond yield and the average public utility bond yield would appear to show a relationship

to the DCF model Dr. Avera's approach simply reinforces past errors into Avista Corporation's future rates, and therefore his approach is circular in its logic.

This Commission has no way of evaluating these other authorized ROEs from other jurisdictions Authorized ROEs from other jurisdictions and under other capital market circumstances do not determine the current cost of equity for Avista Corporation

One would hope that commissions' cost-of-equity methods would improve over time Dr Avera's allowed ROE method locks in the lower common denominator of analyses performed years ago into future rates

Dr. Avera's study in no way corrects for changing industry risk Above, I presented evidence that electric industry risk has declined since the 1974-1979 period Dr Avera's study locks in dated and higher industry risk to the extent that it appropriately estimates the cost of equity at all (which I do not believe).

Dr Avera's analysis does not account for the increasing risk of bonds since about 1970 (bonds can have betas too). I discuss this problem more fully below but the net result is that his method unambiguously overestimates the cost of equity

Finally, Dr Avera's study errs in that even if using other authorized ROEs were valid, he has not determined on what risk-free rates these other allowed ROEs were actually based Commission orders can appear many months after any risk-free rate data on which they were based and taking yearly averages as Dr. Avera does only obscures any relationship. Interest rates declined for much of his period of study Dr. Avera's method is out of step by mismatching authorized ROEs with declining interest rates.

Second, his analysis makes no allowance for changes in electric utility industry risk over the years. In fact, it incorporates varying risk levels over the entire 1946-2002 period, an approach that is certainly inconsistent with his CAPM approach which uses a current beta This approach is really nothing more than the old "comparable earnings method" in stock return clothes

Third, Dr Avera's method does not take into account any increase in single-A rated public utility bonds' risk over the period Below, I discuss Dr Laurence Booth's finding that long-term bonds' betas have increased and how realized excess return premium methods will result in an upwardly biased estimate of the cost of equity to utilities

Fourth, actual returns in the market likely exceeded expected returns for much of the time period on which Dr Avera relied. As Fama and French indicate in their article "Equity Premium" *The Journal of Finance* volume LVII, number 2 (April 2002),

> "Our evidence suggests that the high average return for 1951 to 2000 is due to a decline in discount rates that produces a large unexpected capital gain Our main conclusion is that the average stock return of the last half-century is a lot higher than expected "

Dr Avera chose almost the same period and his analysis is affected by the same problem realized returns exceeded expected returns

Fifth, and most obviously, Dr Avera inappropriately added his premium based on A-rated bonds to a BBB-rated bond yield His mismatch results in a high premium added to a high bond yield resulting in a biased-upward cost of equity estimate. The bias is inherent because A-rated bonds have lower yields than BBB-rated bonds.

Q. HAVE ANY PUBLISHED STUDIES INVESTIGATED THE PROBLEM WITH THE RISK PREMIUM METHOD?

A Yes. Laurence Booth's article "Estimating the Equity Risk Premium and Equity Costs New Ways of Looking at Old Data"[20] investigated the increase in the risk of long-term bonds and found that their betas have been increasing since about 1970. Four of his main conclusions follow

> "(1) Examination of bond market performance and market interest rates experienced since 1925 make it abundantly clear that the *term premium bias* is significant As a result, the long-run realized excess return over long-term bonds cannot be used as a risk premium to add to current long-term bond yields
>
> (2) Total bond market risk (as measured by standard deviation of returns) has significantly increased over the last 20 years, and at time has been almost equal to that of the equity market This indicates that the equity risk premium over long-term bonds is unlikely to have been constant
>
> (3) Bond market betas, whether measured based on ten-year annual returns or five-year monthly returns, have increased from the negligible level prior to the 1970s to the 0.40-0 80 range by 1990s. As a result, conventional risk premiums over long-term bond yields that may have been valid in earlier periods are excessive in the current interest rate environment
>
> **(4) With bond market betas of 0.40-0.80, risk premiums for lower risk equity securities, such as utilities, should be close to zero."**
>
> (emphasis added)

Dr. Avera's realized return approach suffers from upward bias because it did not take into account either the decreasing electric utility betas on one hand or increasing bond betas on the other These two effects have worked since the

[20] Laurence Booth, "Estimating the Equity Risk Premium and Equity Costs New Ways of Looking at Old Data" *Journal of Applied Corporate Finance* Vol 12, No 1 (Spring 1999) pp 100-112

now unavailable to the point of being a "dearth" as the U S Treasury describes it should eliminate any need to consider them because they don't exist. Nevertheless, I will describe below the problems with using a long-term U S Treasury security for the risk-free asset in a CAPM.

Q. IS DR. AVERA'S CHOICE OF A LONG-TERM U.S. TREASURY YIELD FOR THE RISK-FREE RATE APPROPRIATE?

A. No Dr. Avera's choice of a long-term U.S Treasury security yield as the proxy for the risk-free rate is not appropriate for a number of reasons

(1) The CAPM is a holding period model, as I explained earlier One makes estimates of the risk-free rate, beta, and the market risk premium over the investors' expected holding period The use of a long-term U S Treasury bond for the risk-free asset implies a long-term holding period I do not find his implied assumption reasonable Studies I have seen in other cases indicate that investors' holding periods are nearer to two years in length, if not intermediate in term, and I have never seen a study indicating that the average investor has a holding period of greater than twenty-five years, which is the implied holding period in using the risk-free rate Dr Avera chose

(2) I do not see value in using the U.S. Treasury's calculated average rate for December 2003 as a source when Dr Avera could have looked up an actual market-based Treasury yield in *The Wall Street Journal* or other such source to make estimates that were consistent in time with his DCF estimates (December 26, 2003).

(3) I have never seen an academic study of the CAPM use long-term U.S. Treasury bonds for the risk-free asset

(4) Long-term U.S Treasury yields contain a "liquidity risk premium " One could subtract the liquidity risk premium from the long-term rate before using the rate in a CAPM, as described in Brealey and Myers' book, *Principles of Corporate Finance*[21],

> "The risk-free rate could be defined as a long-term Treasury bond yield If you do this, however, you should subtract the risk premium of Treasury bonds over bills .This figure could be in turn be used as an expected average future r_f in the capital asset pricing model "

Dr. Avera did not estimate or subtract the liquidity risk premium from his long-term risk-free rate estimate before using it in his capital asset pricing model Ibbotson Associates' *SBBI 2004 Yearbook* estimates the liquidity risk premium at 1.6 percent (page 175)

(5) Use of a long-term U S. Treasury bond rate creates implementation issues such as the inability to correctly estimate a historical market risk premium and the increased difficulty of estimating beta. For example, a twenty-five-year assumed holding period requires twenty-five years of both stock market data and long-term U S Treasury rate data before an analyst can calculate a single sample historical market risk premium over a twenty-five-year period. The data frequency used in the beta estimate should correspond as well as possible to the assumed holding period The same implementation problem exists for estimating a market risk premium.

[21] Richard A Brealey and Stewart C Myers *Principles of Corporate Finance*,3rd ed , McGraw-Hill Book Co , New York (1988) pp 184

(6) Finally, Dr Avera has a holding-period consistency problem throughout his CAPM analysis that biases his estimates upward I summarize his inconsistencies below in a table

Beta

Q. WHAT BETA ESTIMATE DOES DR. AVERA RELY ON AND HOW DID HE DERIVE IT?

A. Dr Avera's beta estimate is 77, the average *Value Line* beta for his sample

Q. DO YOU AGREE WITH HIS BETA ESTIMATE?

A. No I do not entirely agree with his beta *Value Line*'s adjustment procedure (electric utility betas are adjusted upward toward about 1 0) is not optimal for estimating electric utility betas, as I discussed earlier This upward bias should be at least considered and offered for correction before deriving a cost of equity to the electric utility industry.

Market Risk Premium

Q. WHAT MARKET RISK PREMIUM DOES DR. AVERA RELY ON?

A Dr Avera's market risk premium estimate is 8.5 percent, a DCF-derived market risk premium

Q. HOW DID DR. AVERA ESTIMATE THE MARKET RISK PREMIUM?

A Dr Avera performed a DCF model estimate of the cost of equity to the Standard & Poor's 500 (13.7 percent) and subtracted the same 5 2 percent average December 2003 long-term Treasury bond yield he used for the risk-free rate to arrive at an 8.5 percent market risk premium.

Q. DO YOU AGREE WITH HIS METHOD AND CALCULATIONS?

A. His method might have merit but he has assumed that dividends on the Standard and Poor's 500 composite companies will grow at 12 1 percent per year forever. I find this assumption unreasonable given historical per share dividend growth in the U S stock market (1 09 percent real growth) and historical growth of the U S economy as a whole (3 26 percent real growth) minus share growth that I discussed earlier Those data suggested a 3 to 5 percent nominal growth rate range A leap to 12.1 percent annual per share dividend growth into infinity could not be reasonably expected by investors

Q. PLEASE SUMMARIZE ANY CONSISTENCY ISSUES IN DR. AVERA'S CAPM ANALYSIS AND THEIR BIASES.

A The table below summarizes my findings.

Summary of Dr. Avera's CAPM Application Consistency Issues		
Variable	Implicit Holding Period	Bias/reason
Risk-free rate	Greater than 25 years	Upward bias—doesn't extract liquidity risk premium, data discontinued
Beta	Weekly	Upward bias—calculation assumes shorter than a reasonable holding period assumption and inappropriately adjusted upward to 1.0 without consideration of an unadjusted beta
Market risk premium	Greater than 25 years	Upward bias—unrealistic forecast of indefinite 12 1% dividend growth in the S&P DCF leads to an unrealistically high market risk premium; no consideration of historical premium

Dr. Avera's Flotation Cost Adjustment

Q. IS DR. AVERA'S 0.20 PERCENTAGE POINT FLOTATION COST ADJUSTMENT APPROPRIATE?

A I do not recommend adjusting the cost of equity upward for flotation costs or "market pressure." This topic is controversial and complex Dr Avera has not

shown that Avista Corporation, specifically, will incur any such costs and in what amounts I recommend that the Commission avoid increasing Avista Corp.'s ROE for flotation costs Furthermore, he applies his flotation cost adder to all equity, both contributed capital and retained earnings that never incurred such costs.

Q. PLEASE COMMENT ON DR. AVERA'S FLOTATION COST ADJUSTMENT.

A I have two general points to make about Dr Avera's flotation cost adjustment

1 Dr Avera's flotation cost adjustment compensates Avista for costs that aren't specifically incurred by Avista Corporation The flotation costs appear to be from some undefined study(ies) of costs in other jurisdictions and summarized by Roger Morin in his book.

2. The proposed adjustment lacks support. Dr Avera relies on a conclusion whose study and details are left unexamined by Dr Avera and lacking working papers He presents neither the theory behind his adjustment nor the method of the adjustment nor the details behind the adjustment's calculation. Such an adjustment deserves full presentation if it is to be seriously proposed in this case

Q. DID DR. AVERA ACCOUNT FOR ALL STOCK EXPENSES IN HIS ADJUSTMENT, SUCH AS FEES THAT WOULD REDUCE HIS ESTIMATE?

A No His flotation cost adjustment appears to fail to account for stock purchase fees, otherwise known as brokers' fees, as opposed to the stock issuance fees he did consider. These fees result in an investor paying more than the price quoted on the stock exchange, and would reduce the required dividend yield in the DCF,

offsetting the issuance cost adjustment The effect of brokers' fees is analyzed in David Habr's article, "Commission Staff Report A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," NRRI Quarterly Bulletin 9.1 Brokers' fees of 5 percent would completely offset a 5 percent flotation cost adjustment

Q. SHOULD A UTILITY RECOVER ITS FLOTATION COSTS IN RATES?

A. Yes. Flotation costs are a necessary cost of business However, I recommend that expected normalized issuance expenses be recovered as an expense item, not through a ROE increase

Finally, as I mentioned above, when the market-to-book ratio is greater than 1.0, under the DCF model, a firm is expected to earn more than its cost of capital. The market to book ratio for my sample is 1 62, implying that my sample companies are already expected to earn more than their costs of equity. Boosting the authorized ROE above the cost of equity through a flotation cost adjustment would provide a one-time gain to shareholders at the expense of ratepayers.

Q. DO YOU RECOMMEND THE IDAHO PUC FORMALLY REJECT THE FLOTATION COST ADJUSTMENT TO AVISTA'S ROE IN FAVOR OF THE ACCOUNTING TREATMENT YOU'VE DISCUSSED?

A Yes, I recommend the order in this proceeding find that the flotation cost adjustment to ROE is inappropriate, and should be rejected in favor of an accounting treatment for valid common stock issuance expenses

Dr. Avera's Assessment of Avista's Unique Risk

Q. PLEASE EXPLAIN HOW DR. AVERA JUSTIFIES MOVING TO THE HIGH END OF HIS COST OF EQUITY ESTIMATES TO ACCOUNT FOR AVISTA CORPORATION'S UNIQUE RISK?

A Dr Avera's discussion, beginning on page 60 of his testimony and titled "Relative Risks," concludes that " . the capital markets would require approximately 3 0 to 5 8 percent in additional return in order to compensate for the greater risks associated with speculative grade debt instruments. Investors would undoubtedly require a significantly greater premium for bearing the higher risk associated with the more junior common stock of a utility with Avista's below investment grade rating " (*See* Direct Testimony of Dr Avera, page 62 at 11-15) His analysis leads him to conclude that the uppermost end of his 10.4 to 11.9 percent range is justified

Q. IS DR. AVERA'S RISK ADJUSTMENT APPROPRIATE?

A. No, Dr Avera's increase to his cost of equity estimates to account for Avista Corporation's BB bond rating is not appropriate for several reasons

(1) Increasing a return on equity to account for the unique risks of a company's debt is inconsistent with modern corporate finance theory, notably the capital asset pricing model for which the Nobel Prize in Economics was awarded. Specifically, as I discussed earlier, the CAPM and modern portfolio theory have shown us that investors can avoid risk by diversifying. Since investors can hold diversified portfolios, the only equity risk that remains and is priced in the market is systematic risk. In my example above I discussed a suntan lotion company and an umbrella company. Through diversification, the unique risk of each of the

investments is diversified away and an investor cannot expect, in a competitive market, to be systematically rewarded for taking on risk that is diversified away

(2) Adding a bond rating premium to a cost of equity analysis is not consistent with either the CAPM or the DCF Adding a bond premium to an equity cost is arbitrary and unwarranted

(3) Adding a unique risk adder to Avista Corporation because of its poor financial situation would inappropriately compensate investors for the Company's past imprudence to the extent that past imprudence, or utility diversification, contributed to its current financial situation and below-investment-grade ratings

Q. HAS THIS ISSUE OF INCLUDING UNIQUE RISK IN A COST OF EQUITY ANALYSIS BEEN ADDRESSED IN A RECENT PUBLICATION?

A Yes The issue has been addressed in award-winning article titled "How Improper Risk Assessment Leads to Overstatement of Required Returns for Utility Stocks" published in the *National Regulatory Research Institute Journal of Applied Regulation*, Vol 1, June 2003 That article concludes,

> "Risk and return are important issues in regulatory proceedings. Understanding how risks affect stock prices leads to better estimates of the market's required return on utility stocks. Risks that are specific to the utility affect expectations about future utility cash flows, but they have little bearing on the investors' required return Regulators should therefore ignore testimony suggesting that firm-specific risks influence the required return. Once the inappropriate firm-specific risk adjustments are eliminated, regulators will likely find that required returns on most utility stocks today are below 10% "

I include that article as pages 24-47 of Exhibit JST–1. The proper approach to estimating the cost of equity to Avista Corporation is by using market-based

models of the cost of equity to firms of comparable risk rather than by arbitrarily adding risk adjustments to account for firm-specific unique risks

Q. DO BOND HOLDERS AND COMMON EQUITY OWNERS HAVE THE SAME INTERESTS AND CAN BOND YIELDS BE DIRECTLY COMPARED TO REQUIRED RETURNS ON EQUITY?

A. Bond holders and stockholders frequently have divergent interests Bond holders might very well focus on firm-specific risk because they are concerned about the probability of default, a probability that is affected by firm-specific issues and measured by bond ratings. The reason for this focus of concern is that, unlike a stock, bond holders' expected returns are capped at the coupon rate of debt That is to say, even if the firm has excess returns it will still, at best, only pay out to bond holders the coupon rate of the outstanding debt. For example, say a utility issues 8 percent coupon debt The most it will ever pay bondholders is 8 percent but the company might pay less than 8 percent if the bonds have any risk at all An investor's expected return on the bond is, therefore, less than 8 percent and might be 7 percent for example The possibility of default means that the bond holders' expected returns are actually lower than the coupon rate of debt Therefore, bond holders focus on the probability of default. Adding a bond holder's default premium for Avista Corporation's BB-rated bonds to a cost of equity is, therefore, inappropriate because the two are not comparable.

Dr. Avera's Cost of Equity Conclusion

Q. WHAT IS DR. AVERA'S COST OF EQUITY CONCLUSION?

A Dr. Avera concludes that Avista Corporation's required return on equity falls in the upper end of his 10 4 to 11 9 percent cost of equity range and that the 11 5 percent ROE that Avista requested is conservative. His cost of equity estimates go as high as 17 7 percent (11.7 percent from the electric industry CAPM plus the 0 20 percent flotation cost adjustment plus the 5.8 percent unique risk adder).

Conclusion

Q. WHAT DO YOU CONCLUDE GIVEN THE EVIDENCE YOU REVIEWED?

A I conclude that the Commission should authorize an 8.5 percent ROE and an 8 49 percent ROR, but I offer two other alternatives based on my high and low cost of equity estimates

The Commission should reject Mr Malquist's 11.5 percent recommendation because it is not based on a cost of equity analysis or any other evidence other than his personal belief.

Dr Avera significantly overestimated Avista Corporation's cost of equity, particularly in a period when interest rates are not far from historical post-war lows His adder for the unique risk of Avista Corporation is also inappropriate. His analyses are upwardly biased and inconsistent with current capital markets and capital market theory.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A Yes, it does

Appendix

Derivation of the Constant-Growth DCF Model Cost of Equity

Stock I's price today (P_0) is equal to its value, which in turn is worth the present discounted value of its expected dividends ($D_{1\ n}$), discounted by the stock's cost of equity ($\mathbf{k_i}$)

$$(1) \quad P_0 = \frac{D_1}{(1 + k_i)} + \frac{D_2}{(1 + k_i)^2} + \frac{D_3}{(1 + k_i)^3} + \ldots + \frac{D_n}{(1 + k_i)^n}$$

Now assume that dividends 2 through n are related to dividend 1 by a constant growth rate, g_i, such that:

$$(2) \quad D_2 = D_1 \times (1 + g_i)$$
$$(3) \quad D_3 = D_1 \times (1 + g_i)^2$$
$$(4) \quad D_n = D_1 \times (1 + g_i)^{n-1}$$

Expressing equation (4) in terms of D_1

$$(5) \quad P_0 = \frac{D_1}{(1 + k_i)} + \frac{D_1 \times (1+g_i)}{(1 + k_i)^2} + \frac{D_1 \times (1 + g_i)^2}{(1 + k_i)^3} + \quad + \frac{D_1 \times (1 + g_i)^{n-1}}{(1 + k_i)^n}$$

Now, multiply each side by $1 + k_i$

$$(6) \quad P_0 \times (1 + k_1) = D_1 + \frac{D_1 \times (1 + g_1)}{(1 + k_1)} + \frac{D_1 \times (1 + g_1)^2}{(1 + k_1)^2} + \ldots + \frac{D_1 \times (1+g_1)^{n-1}}{(1 + k_1)^{n-1}}$$

The right hand side of the equation can be expressed using summation notation.

$$(7) \quad P_0 \times (1 + k_1) = \sum_{t=0}^{n-1} D_1 \times \frac{(1+g_1)^t}{(1 + k_1)^t}$$

Now, we assume that dividends are paid infinitely ($n \to \infty$) The right hand side of equation (7) becomes the sum of a geometric series We can simplify equation (7) by assuming that $k_i > g_i$ (for convergence):

$$(8) \quad P_0 \; x \; (\; 1 + k_t \;) = \frac{D_1}{1 - \frac{(\; 1 + g_t \;)}{(\; 1 + k_t \;)}}$$

Simplifying

$$(9) \quad P_0 \; x \; (\; 1 + k_t \;) = \frac{D_1}{\frac{1 + k_t - 1 - g_t}{(\; 1 + k_t \;)}}$$

Canceling terms and simplifying further

$$(10) \quad P_0 = \frac{D_1}{k_t - g_t}$$

Manipulating equation (10) to solve for the cost of equity

$$(11) \quad k_t = \frac{D_1}{P_0} + g_t$$

This is the constant-growth DCF formula for the cost of equity and is often referred to as "the Gordon model."

Note that this proof does not require any assumption of the relationship between D_0 and D_1.

Demonstration that Expected Market ROE is Greater than Expected Book ROE when M/B Ratio is Greater than 1 0

Start by assuming that the expected market return in dollars (expected market ROE times the market value of equity) is equal to the expected book return in dollars (expected book ROE times the book value of equity),

$$k_t \; x \; M = r_{Book} \; x \; B$$

Move the expected rates of return to the right hand side and the equity values to the left hand side,

$$\frac{M}{B} = \frac{r_{Book}}{k_t}$$

Now make the observation that if M/B equals 1.0 then r_{Book} must equal k_t because the ratio r_{Book}/k_t is also equal to one. However, if M/B is greater than 1 0, then the ratio r_{Book}/k_t is greater than 1 0, and therefore, the expected book ROE must be greater than the expected market ROE.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	Case Nos. AVU-E-04-1 AVU-G-04-1

EVIDENCE SUPPORTING THE

DIRECT TESTIMONY OF JOHN S. THORNTON

ON BEHALF OF POTLATCH CORPORATION

June 21, 2004

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Avista Corporation
Overall Rate of Return Recommendation
and Range Estimates

Avista Corporation's ROR at Recommended Return on Equity
Applicant's Proposed Capital Structure and Costs of Debt and Preferred Stock

(A) Capital Source	(B) $	(C) Capital Structure	*	(D) Cost	=	(E) Weighted Cost
Debt	$ 832,735,414	48 19%		8.70%		4 19%
Trust Preferred Securities	$ 100,000,000	5.79%		7 01%		0 41%
Preferred stock	$ 29,750,000	1 72%		7 34%		0 13%
Common equity	$ 765,520,415	44 30%		8 50%		3 77%
Totals.	$ 1,728,005,829	100.00%				**8.49%**

Interest coverage ratio·
=(E7+(E8+E9+E10*1.65)/E7 **2.69**

Avista Corporation's ROR at High Cost of Equity Estimate
Applicant's Proposed Capital Structure and Costs of Debt and Preferred Stock

(A) Capital Source	(B) $	(C) Capital Structure	*	(D) Cost	=	(E) Weighted Cost
Debt	$ 832,735,414	48 19%		8 70%		4 19%
Trust Preferred Securities	$ 100,000,000	5.79%		7 01%		0 41%
Preferred stock	$ 29,750,000	1.72%		7 34%		0 13%
Common equity	$ 765,520,415	44.30%		9 90%		4.39%
Totals·	$ 1,728,005,829	100.00%				**9.11%**

Interest coverage ratio·
=(E24+(E25+E26+E27)*1.65)/E24 **2.94**

Avista Corporation's ROR at Low Cost of Equity Estimate
Applicant's Proposed Capital Structure and Costs of Debt and Preferred Stock

(A) Capital Source	(B) $	(C) Capital Structure	*	(D) Cost	=	(E) Weighted Cost
Debt	$ 832,735,414	48 19%		8.70%		4.19%
Trust Preferred Securities	$ 100,000,000	5.79%		7 01%		0 41%
Preferred stock	$ 29,750,000	1 72%		7.34%		0.13%
Common equity	$ 765,520,415	44 30%		7.50%		3 32%
Totals:	$ 1,728,005,829	100.00%				**8.05%**

Interest coverage ratio·
=(E42+(E42+E43+E44)*1 65)/E42 **2.52**

"ONE OF THE BEST INVESTMENT BOOKS OF ALL TIME...THIS IS THE BUY-AND-HOLD BIBLE."

—James K. Glassman, *The Washington Post*, on 2nd edition of *Stocks for the Long Run*

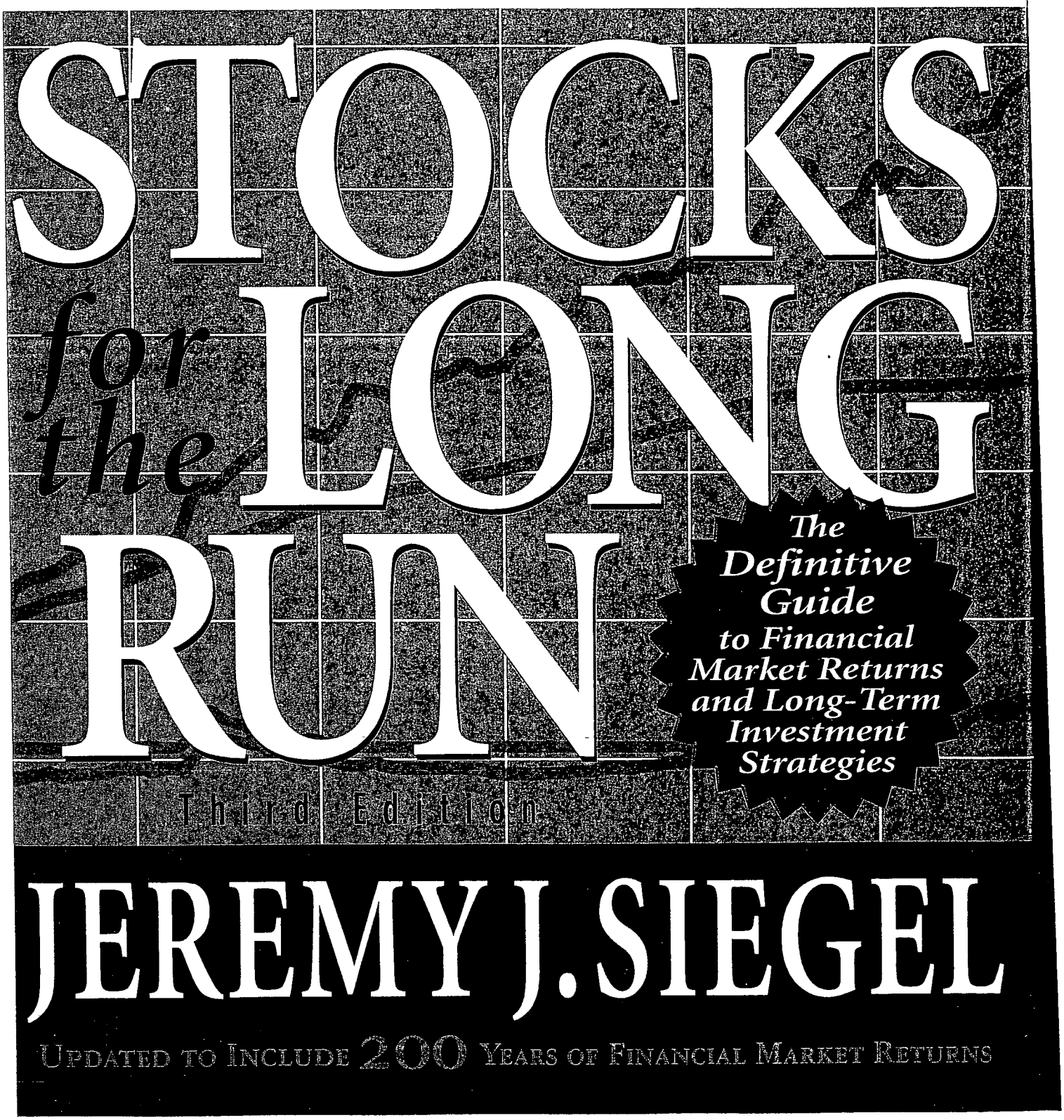
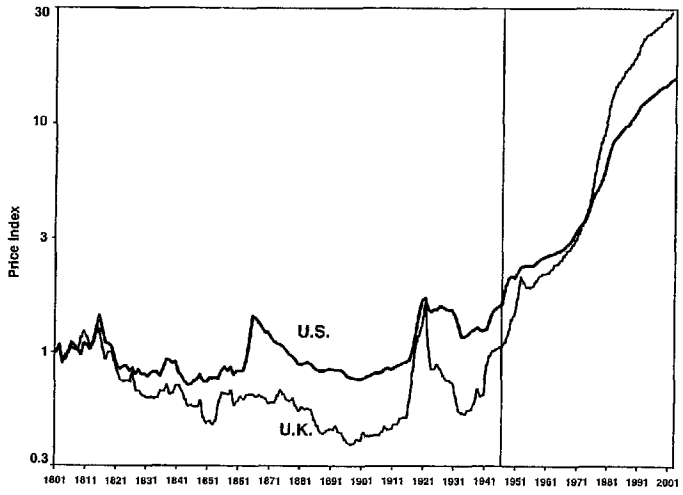


FIGURE 1–3

U S and U K Price Indexes, 1800–2001 (1800 = $1)



It is not surprising that the price of gold has followed the trend of overall inflation closely over the past two centuries The price of gold soared to $850 per ounce in January 1980, following the rapid inflation of the preceding decade When inflation was brought under control, the price of gold fell One dollar of gold bullion purchased in 1802 was worth $14 38 at the end of 2001 That is actually less than the change in the overall price level[11] In the long run, gold offers investors some protection against inflation but little else Whatever hedging property precious metals possess, these assets will exert a considerable drag on the return of a long-term investor's portfolio.[12]

[12]Ironically, despite the inflationary bias of a paper money system, well-preserved paper money from the early nineteenth century is worth many times its face value on the collectors' market, far surpassing gold bullion as a long-term investment An old mattress found containing nineteenth-century paper money is a better find for the antique hunter than an equivalent sum hoarded in gold bars!

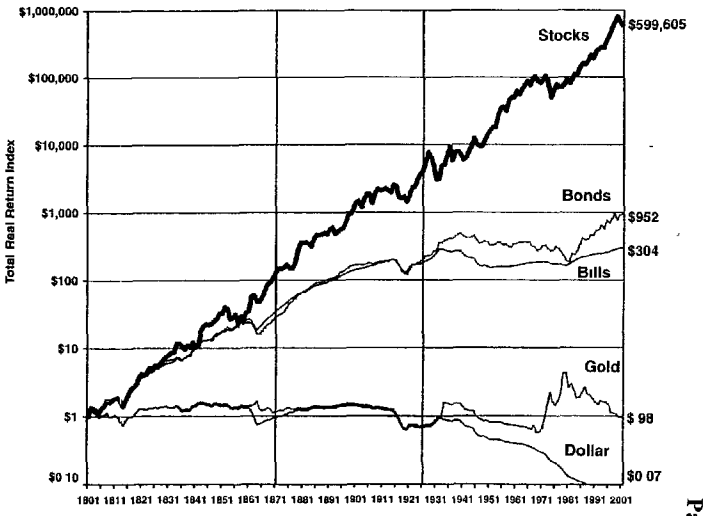
TOTAL REAL RETURNS

The focus of every long-term investor should be the growth of purchasing power—monetary wealth adjusted for the effect of inflation Figure 1-4 shows the growth of purchasing power, or total real returns, in the same assets that were graphed in Figure 1-1 stocks, bonds, bills and gold These data are constructed by taking the dollar returns and correcting them by the changes in price level shown in Figure 1-3 [13]

[13]Total returns are graphed on a ratio, or logarithmic, scale Economists use this scale to graph virtually all long-term data because equal vertical distances anywhere in the chart represent equal percentage changes in return As a result, a constant slope represents a constant after-inflation rate of return

FIGURE 1–4

Total Real Return Indexes, 1802–2001



Page 3

The growth of purchasing power in equities not only dominates all other assets but also shows remarkable long-term stability Despite extraordinary changes in the economic, social, and political environments over the past two centuries, stocks have yielded between 6 6 and 7 0 percent per year after inflation in all major subperiods

The wiggles on the stock return line represent the bull and bear markets that equities have suffered throughout history The long-term perspective radically changes one's view of the risk of stocks. The short-term fluctuations in the stock market, which loom so large to investors when they occur, are insignificant when compared with the upward movement of equity values over time

In contrast to the remarkable stability of stock returns, real returns on fixed-income assets have declined markedly over time In the first and even second subperiods, the annual returns on bonds and bills, although less than those on equities, were significantly positive Since 1926, however, and especially since World War II, fixed-income assets have returned little after inflation

INTERPRETATION OF RETURNS

Long-Period Returns

Table 1-1 summarizes the annual returns on U S stocks over the past two centuries [14] The shaded column represents the real after-inflation, compound annual rate of return on stocks The real return on equities has averaged 6 9 percent per year over the past 200 years This means that purchasing power has, on average, doubled in the stock market every 10 years If past trends persist, inflation averages 3 percent, and equities offer a 7 percent real return, this would translate into a 10 2 percent per year nominal or money return on stocks

Note the extraordinary stability of the real return on stocks over all major subperiods 7 0 percent per year from 1802 through 1870, 6 6 percent from 1871 through 1925, and 6 9 percent per year since 1926 Even

[14]The dividend yield for the first subperiod has been estimated by statistically fitting the relation of long-term interest rates to dividend yields in the second subperiod, yielding results that are closer to other information we have about dividends during the period See Walter Werner and Steven Smith, *Wall Street* (New York. Columbia University Press, 1991), for a description of some early dividend yields See also recent papers by William Goetzmann and Phillipe Jorion, "A Longer Look at Dividend Yields," *Journal of Business* 68(4)(1995) 483–508, and by William Goetzmann, "Patterns in Three Centuries of Stock Market Prices," *Journal of Business* 66(2)(1993) 249–270

TABLE 1–1

Annual Stock Market Returns, 1802–2001

Comp = compound annual return
Arith = arithmetic average of annual returns
Risk = standard deviation of arithmetic returns
All Data in Percent (%)

		Total Nominal Return			Nominal Capital Appreciation			Div Yld	Total Real Return			Real Capital Appreciation			Real Gold Retn	Consum Price Inflation
		Comp	Arith	*Risk*	Comp	Arith	*Risk*		Comp	Arith	*Risk*	Comp	Arith	*Risk*		
Periods	1802-2001	8 3	9 7	*17 5*	3 0	4 4	*17 5*	5 2	6 9	8 4	*18 1*	1 6	3 2	*17 9*	0 0	1 4
	1871-2001	9 0	10 6	*18 5*	4 2	5 8	*18 3*	4 6	6 8	8 5	*18 8*	2 1	3 8	*18 6*	-0 1	2 0
Major Sub-Periods	I 1802-1870	7 1	8 1	*15 5*	0 7	1 8	*15 5*	6 4	7 0	8 3	*16 9*	0 6	1 9	*16 6*	0 2	0 1
	II 1871-1925	7 2	8 4	*15 7*	1 9	3 1	*16 1*	5 2	6 6	7 9	*16 8*	1 3	2 7	*17 1*	-0 8	0 6
	III 1926-2001	10 2	12 2	*20 3*	5 8	7 8	*19 6*	4 1	6 9	8 9	*20 3*	2 7	4 6	*19 6*	0 4	3 1
Post-War Periods	1946-2001	11 6	12 8	*16 8*	7 5	8 7	*16 2*	3 8	7 1	8 6	*17 4*	3 2	4 6	*16 8*	-0 3	4 1
	1946-1965	13.1	14 3	*19 5*	8 2	9 2	*18 7*	4 6	10 0	11 4	*18 7*	5.2	6 5	*18 1*	-2 7	2 8
	1966-1981	6 6	8 3	*17 2*	2 6	4 3	*16 6*	3.9	0 4	1 4	*17 1*	-4 1	-2 4	*16 7*	8 8	7 0
	1982-1999	17 3	18 0	*12 5*	13 8	14 5	*12 4*	3 1	13 6	14 3	*12 6*	10 2	10 9	*12 6*	-4.9	3 3
	1982-2001	14 1	15 0	*14 9*	10 9	11 8	*14 4*	2 9	10 5	11 5	*14 7*	7 4	8 3	*14 3*	-4 8	3 2

since World War II, during which all the inflation that the United States has experienced over the past 200 years occurred, the average real rate of return on stocks has been 7 1 percent per year This is virtually identi to the preceding 125 years, which saw no overall inflation This rema able stability of long-term real returns is a characteristic of *mean reversion*, a property of a variable to offset its short-term fluctuations so as to produce far more stable long-term returns

The long-term stability of these returns is all the more surprising when one reflects on the dramatic changes that have taken place in our society during the last two centuries The United States evolved from an agricultural to an industrial economy and now to a postindustrial service- and technology-oriented economy The world shifted from a gold standard to a paper money standard And information, which once took weeks to cross the country, can now be transmitted instantaneously and broadcast simultaneously around the world Yet, despite mammoth changes in the basic factors generating wealth for shareholders, equity returns have shown an astounding persistence

Short-Period Returns

The long-term stability of real equity returns does not deny that short-term returns can be quite variable In fact, there are a number of periods when stock returns differ from their long-term average Samples of such episodes after World War II are reported at the bottom of Table 1-1

The bull market from 1982 through 1999 gave investors an after-inflation return of 13 6 percent per year, which is nearly double the historical average However, the superior equity returns over this period have barely compensated investors for the dreadful stock returns realized in the preceding 15 years, from 1966 through 1981, when the real rate of return was −0 4 percent In fact, during the 15-year period that preceded the current bull market, stock returns were more below their historical average than they have been above their average during the 1982–1999 great bull market run

The bull market since 1982 has brought stocks back from the extremely undervalued state that they reached at the beginning of the 1980s Certainly the superior performance of stocks over the last decade is extremely unlikely to persist, but this does not necessarily imply that stock returns over the next decade must be below average in order to offset the bull market from 1982 Chapter 7 will analyze future returns on stocks in light of the great bull market of the past two decades

REAL RETURNS ON FIXED-INCOME ASSETS

As stable as the long-term real returns have been for equities, the same cannot be said of fixed-income assets Table 1-2 reports the nominal and real returns on both short- and long-term bonds over the same time periods as in Table 1-1 The real return on bills has dropped precipitously from 5 1 percent in the early part of the nineteenth century to a bare 0 7 percent since 1926, a return only slightly above inflation

The real return on long-term bonds has shown a similar pattern Bond returns fell from a generous 4 8 percent in the first subperiod to 3 7 percent in the second and then to only 2 2 percent in the third If the returns from the last 75 years were projected into the future, it would take nearly 33 years to double one's purchasing power in bonds and over 100 years to do so in Treasury bills in contrast to the 10 years it takes in stocks

The decline in the average real return on fixed-income securities is striking In any 30-year period beginning with 1889, the average real rate of return on short-term government securities has exceeded 2 percent only three times Since the late nineteenth century, the real return on

TABLE 1–2

Fixed-Income Returns, 1802–2001

Comp = compound annual return
Arith = arithmetic average of annual returns
Risk = standard deviation of arithmetic returns
All Data in Percent (%)

		Long-Term Governments						Short-Term Governments				Consumer Price Inflation
		Coupon Rate	Nominal Return			Real Return			Nominal Rate	Real Return		
			Comp	Arith	Risk	Comp	Arith	Risk		Comp	Arith	Risk	
Periods	1802-2001	4 8	4 9	5 1	6 3	1 5	3 9	8 9	4 3	2 9	3 1	6 1	1 4
	1871-2001	4 7	4 9	5 1	7 5	2 0	3 2	9 1	3 8	1 7	1 9	4 6	2 0
Major Sub-Periods	I 1802-1870	4 9	4 9	4 9	2 8	4 8	5 1	8 3	5 2	5 1	5 4	7 7	0 1
	II 1871-1925	4.0	4.3	4 4	3 0	3 7	3 9	6 4	3 8	3 2	3 3	4 8	0 6
	III 1926-2001	5.2	5 3	5 7	9 5	2 2	2 7	10 7	3 9	0 7	0 8	4 1	3 1
Post-War Periods	1946-2001	6 0	5 5	6 0	10 7	1 9	1 9	11 5	4 9	0 5	0 7	3 3	4 1
	1946-1965	3.1	1.6	1 7	7 1	-1 2	-1 0	8 1	2 0	-0 9	-0 7	2 1	2 8
	1966-1981	7 2	2 5	2 8	12 3	-4 2	-3 9	13 2	6 9	-0 2	-0 1	2 4	7 0
	1982-1999	8.4	12 0	12 8	14 4	8 4	9 3	14 2	6 3	2 9	2 9	1 8	3.3
	1982-2001	8 1	12.0	12 8	13 8	9 6	9 3	13 6	6 1	2 6	2 8	1 7	3 2

bonds and bills over any 30-year horizon has seldom matched the average return of 4 5 to 5 percent reached during the first 70 years of sample From 1880, the real return on long-term bonds over every 30-year period has never reached 4 percent, and it exceeded 3 percent during only 17 such periods

You have to go back more than 1½ centuries to the period from 1831 through 1861 to find any 30-year period where the return on either long- or short-term bonds exceeded that on equities The dominance of stocks over fixed-income securities is overwhelming for investors with long horizons

THE FALL IN FIXED-INCOME RETURNS

Although the returns on equities have fully compensated stock investors for the increased inflation since World War II, the returns on fixed-income securities have not The change in the monetary standard from gold to

paper had its greatest effect on the returns of fixed-income assets It is clear that the buyers of long-term bonds in the 1940s, 1950s, and early 1960s did not recognize the inflationary consequences of the change in monetary regime How else can you explain why investors voluntarily purchased 30-year bonds with 3 and 4 percent coupons, ignoring a government policy that was determined to avoid deflation and in fact favored inflation?

However, there must have been other reasons for the decline in real returns on fixed-income assets Theoretically, the unanticipated inflation of the postwar period should have had a significantly smaller effect on the real return on short-term bonds such as Treasury bills This is so because short-term rates may be reset frequently to capture expected inflation As noted previously, however, the decline in the real return on short-term bonds actually exceeded the decline in the real return on long-term bonds

Another explanation for the fall in bond returns is investors' reactions to the financial turmoil of the Great Depression The stock collapse of the early 1930s caused a whole generation of investors to shun equities and invest in government bonds and newly insured bank deposits, driving their return downward Finally, many investors bought bonds because of the widespread (but incorrect) prediction that another depression would follow the war

However, it was not just the risk preferences of investors that kept fixed rates low The Federal Reserve actively supported the bond market through much of the 1940s to keep the government's interest expense low Thus support policy was abandoned in 1951 because it led to interest rates that were inconsistent with one of the Fed's primary goals of maintaining low inflation

And finally, one should not ignore the transformation of a highly segmented market for short-term instruments in the nineteenth century into one of the world's most liquid markets Treasury bills satisfy certain fiduciary and legal requirements that no other asset can match The premium paid for these services, however, has translated into a meager return for investors

EQUITY PREMIUM

Whatever the reasons for the decline in the real return on fixed-income assets over the past century, it is almost certain that the real returns on bonds will be higher on average in the future than they have been over the last 70 years As a result of the inflation shock of the 1970s, bondholders have incorporated a significant inflation premium in the coupon on long-term bonds In most major industrialized nations, if inflation

does not increase appreciably from current levels, real returns of about 2 to 3 percent will be realized from government bonds whose nominal rate is between 5 and 6 percent These projected real returns are not much lower than the 3½ percent average compound real return on U S long-term government bonds over the past 200 years Moreover, they are comparable with the yields of the newly floated inflation-linked bonds issued by the U S Treasury in 1997

The excess return for holding equities over short-term bonds is referred to as the *equity risk premium*, or simply the *equity premium*, and is plotted in Figure 1-5 [15] The equity premium, calculated as the difference

[15]For a rigorous analysis of the equity premium, see Jeremy Siegel and Richard Thaler, "The Equity Premium Puzzle," *Journal of Economic Perspectives* 11(1)(Winter 1997) 191–200

FIGURE 1–5

Equity Risk Premium (30-Year Compound Annual Moving Average, 1831–2001)

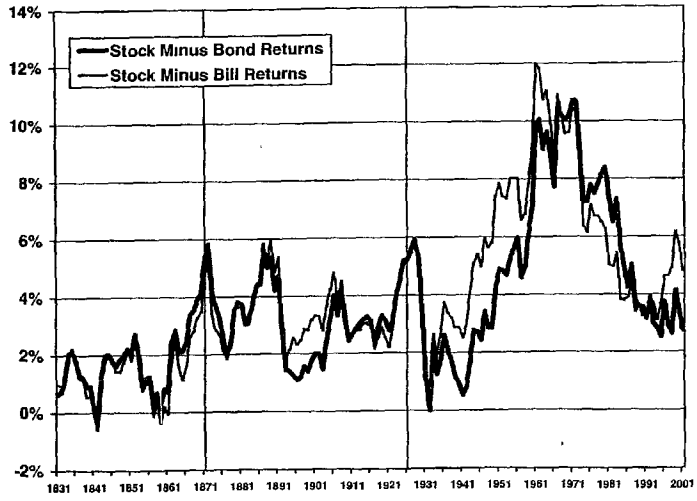


Exhibit JST-1
Page 6

in 30-year compound annual real returns on stocks and bills, averaged 1.9 percent in the first subperiod, 3 4 percent in the second subperiod, and 6 5 percent since 1926.

The abnormally high equity premium since 1926 is certainly not sustainable It is not a coincidence that the highest 30-year average equity return occurred in a period marked by very low real returns on bonds Since firms finance a large part of their capital investment with bonds, the low cost of obtaining such funds increased returns to shareholders The 1930s and 1940s marked an extremely undervalued period for equities and overvalued period for government bonds, leading to unusually high returns for stocks and low returns for bonds. As stocks and bonds become more correctly priced, the equity premium certainly will shrink Chapter 7 will discuss the equity premium and its implications for future returns in more detail

INTERNATIONAL RETURNS

Some economists have maintained that the superior returns to equity are a consequence of choosing data from the United States, a country that has been transformed from a small British colony to the world's greatest economic power over the last 200 years [16] However, equity returns in other countries also have substantially outpaced those on fixed-income assets

Figure 1-6 displays the total real stock return index for the United States, the United Kingdom, Germany, and Japan from 1926 to the present [17] It is striking that the cumulative real returns on German and U K stocks over the 76-year period from 1926 through 2001 come so close to those of the United States The compound annual real returns on stocks in each of these three countries are all within about 1 percentage point of each other

The collapse of Japanese stocks during and after World War II was far greater than occurred in its defeated ally, Germany In Japan, the breakup of the *Zaibatsu* industrial cartel, the distribution of its shares to the workers, and the hyperinflation that followed the war caused a 98 percent fall in the real value of equities [18]

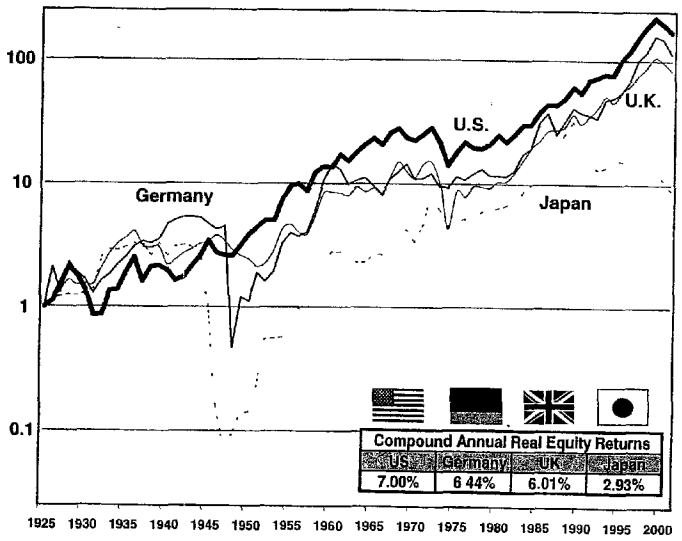
[16] See S J Brown, W N Goetzmann, and S A Ross, "Survival," *Journal of Finance* 50(1995) 853–873

[17] The German returns are obtained from Gregor Gielen, *Konnen Aktienkurse Noch Steigen? Langfristige Trendanalyse des deutschen Aktienmarktes* (Berlin Gabler, 1994) British returns are from Shiller (1989) and updated from various sources

[18] T F M Adams and Iwao Hoshii, *A Financial History of the New Japan* (Tokyo Kodansha International, 1972), p 39

FIGURE 1–6

International Real Stock Returns in the United States, Germany, the United Kingdom, and Japan, 1926–2001



Despite the collapse of the equity market, Japanese stocks regained almost all the ground they lost to the Western countries by the end of the 1980s From 1948 through 1989, the real return on the Japanese market has exceeded 10 4 percent per year, nearly 50 percent higher than the U.S market Even including its recent bear market, Japan's real equity returns since 1926 have been 2 9 percent per year Moreover, because the yen has appreciated in real terms relative to the dollar, the average annual real-dollar returns in the Japanese market have been 3 15 percent per year Measured in *any* currency, the real returns in *every* one of these

Exhibit JST-1
Page 7

major countries from 1926 through 2001 have exceeded the real returns on fixed-income assets in *any* of these countries

Germany

Despite the fact that World War II resulted in a 90 percent drop in real German equity prices, investors were not wiped out Those who patiently held equity were rewarded with tremendous returns in the postwar period [19] By 1958, the total returns for German stocks had surpassed its prewar level In the 12 years from 1948 through 1960, German stocks rose by over 30 percent per year in real terms Indeed, from 1939, when the Germans invaded Poland, through 1960, the real returns on German stocks nearly matched those in the United States and exceeded those in the United Kingdom Despite the devastation of the war, the recovery of German markets powerfully attests to the resilience of stocks in the face of seemingly destructive political, social, and economic forces

United Kingdom

Over the long run, the returns on British equities are almost as impressive as those in the American market In contrast to the U S experience, the greatest stock decline in Great Britain occurred in 1973 and 1974, not the early 1930s In 1973–1974, rampant inflation as well as political and labor turmoil caused the British market to lose over 70 percent of its value The capitalization of the British market fell to a measly $50 billion This is less than the market value of many individual Internet stocks during the height of the dot-com mania in 1999–2000 or the yearly profits of the OPEC oil-producing nations, whose increase in oil prices contributed to the decline in share values [20]

In fact, the OPEC nations could have purchased a controlling interest in every publicly traded British corporation in the 1970s with less than 1 year's oil revenues! It is lucky for the British that they did not The British market has increased dramatically since the 1974 crash and has outstripped the dollar gains in all other major world markets Again,

[19]Of course, not everyone in Germany was able to realize the German postwar miracle The stock holdings of many who resided in the eastern sector, controlled by the Soviet Union, were totally confiscated Despite reunification with West Germany, many of these claims were never recovered

[20]"The défi Opec" (no author), *The Economist*, December 7, 1974, p 85 OPEC stands for "Organization of Petroleum Exporting Countries," a cartel that attempts to regulate the supply of oil

these rewards went to those who held onto British stocks through this crisis

Japan

Despite Japan's recent bear market, the postwar rise in Japanese stocks is quite remarkable The Nikkei Dow Jones Stock Average, patterned after the U S Dow Jones Average and containing 225 stocks, was first published on May 16, 1949 The day marked the reopening of the Tokyo Stock Exchange, which had been officially closed since August 1945 On the opening day, the value of the Nikkei was 176 21—virtually identical to the U S Dow Jones Industrials at that time By December 1989, the Nikkei soared to nearly 40,000, more than 15 times that of the Dow Japan's bear market brought the Nikkei below 10,000 following the terrorist attacks in September 2001, just above the level reached by the American Dow On February 1, 2002, the Nikkei closed at 9,791, below the Dow for the first time in 45 years

However, comparing U S and Japanese Dow indexes overstates the extent of the Japanese decline The gain in the Japanese market measured in *dollars* far exceeds that measured in *yen* The yen was set at 360 to the dollar 3 weeks before the opening of the Tokyo Stock Exchange—a rate that was to hold for more than 20 years Since then, the dollar has fallen to about 130 yen In dollar terms, therefore, the Nikkei climbed to over 100,000 in 1989 and is currently over 30,000, three times its American counterpart, despite the great bear market that has enveloped Japan in the past decade

Foreign Bonds

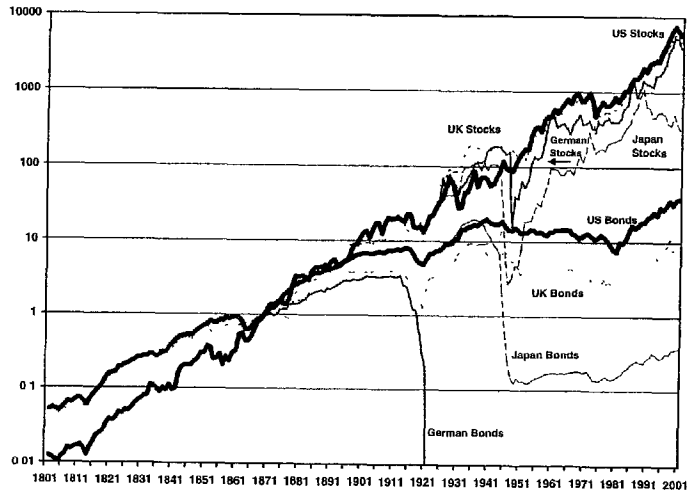
The story for foreign countries remains the same as that of the United States Stocks dominate bonds over all long-term periods The postwar hyperinflation, when the yen was devalued from 4 to the dollar to 360 to the dollar, wiped out Japanese bondholders However, nothing compares with the devastation experienced by German bondholders during the 1922–1923 hyperinflation, when the reichsmark was devalued by more than 10 billion to one. All German fixed-income assets were rendered worthless, yet stocks, which represented claims on real land and capital, weathered the crisis

Figure 1-7 summarizes the return on international bonds as well as stocks The superiority of stocks to fixed-income investments over the

Exhibit JST-1
Page 8

FIGURE 1–7

International Total Real Stock and Bond Returns, 1802–2001



long run is indisputable Stocks not only outperform bonds on the basis of return but also display far greater stability of purchasing power

CONCLUSION

Over the past 200 years, the compound annual real return on a diversified portfolio of common stock is nearly 7 percent in the United States and has displayed a remarkable constancy over time The reasons for the persistence and long-term stability of stock returns are not well understood Certainly the returns on stocks depend on the quantity and quality of capital, productivity, and the return to risk taking However, the ability to create value also springs from skillful management, a stable political system that respects property rights, and the capacity to provide value to consumers in a competitive environment Swings in investor sentiment resulting from political or economic crises can throw stocks off their long-term path, but the fundamental forces producing economic growth enable equities to regain their long-term trend Perhaps this is why long-term stock returns have displayed such stability despite the radical political, economic, and social changes that have affected the world over the past two centuries

The superior returns to equity over the past two centuries might be explained by the growing dominance of nations committed to free-market economics Who might have expected the triumph of market-oriented economies 50 or even 30 years ago? The robustness of world equity prices in recent years might reflect the emergence of the golden age of capitalism—a system in ascendancy today but whose fortunes could decline in the future Yet, even if capitalism declines, it is unclear which assets, if any, will retain value In fact, if history is any guide, government bonds in our paper-money world may fare far worse than stocks in any political or economic upheaval As the next chapter shows, the risks in bonds actually outweigh those in stocks over long horizons

APPENDIX 1: STOCKS FROM 1802 TO 1871

The first actively traded U S stocks, floated in 1791, were two banks. the Bank of New York and the Bank of the United States [21] Both offerings were enormously successful and were quickly bid to a premium However, they collapsed the following year when Alexander Hamilton's assistant at the Treasury, William Duer, attempted to manipulate the market and precipitated a crash It was from this crisis that the antecedents of the New York Stock Exchange were born on May 17, 1792

Joseph David, an expert on the eighteenth-century corporation, claimed that equity capital was readily forthcoming not only for every undertaking likely to be profitable but, in his words, "for innumerable undertakings in which the risk was very great and the chances of success were remote "[22] Although over 300 business corporations were chartered by the states before 1801, fewer than 10 had securities that traded on a regular basis Two-thirds of those chartered before 1801 were connected with transportation wharves, canals, turnpikes, and bridges However,

[21]The oldest continuously operating firm is Dexter Corp , founded in 1767, a Connecticut maker of special materials, the second is Bowne & Co (1775), which specializes in printing, the third is CoreStates Financial Corp , founded in 1782 as the First National Bank of Pennsylvania, and the fourth is the Bank of New York Corp , founded in 1782, which was involved in the successful 1791 stock offering with the Bank of the United States that eventually was involved in the crash of 1792

[22]Werner and Smith (1991), p 82

Exhibit JSI-1
Page 9

the important stocks of the early nineteenth century were financial institutions banks and, later, insurance companies. Banks and insurance companies held loans and equity in many of the manufacturing firms that, at that time, did not have the financial standing to issue equity The fluctuations in the stock prices of financial firms in the nineteenth century reflected the health of the general economy and the profitability of the firms to whom they lent The first large nonfinancial venture was the Delaware and Hudson Canal, which issued stock in 1825 and also became an original member of the Dow Jones Industrial Average 60 years later In 1830, the first railroad, the Mohawk and Hudson, was listed, and for the next 50 years, railroads dominated trading on the major exchanges

APPENDIX 2: ARITHMETIC AND GEOMETRIC RETURNS

The average arithmetic return r_A is the average of each yearly return If r_1 to r_n are the n yearly returns, $r_A = (r_1 + r_2 \quad + r_n)/n$ The average geometric or compound return r_G is the nth root of the product of 1-year total returns minus 1 Mathematically, this is expressed as $r_G = [(1 + r_1)(1 + r_2) \quad (1 + r_n)]^{1/n} - 1$ An asset that achieves a geometric return of r_G will accumulate to $(1 + r_G)^n$ times the initial investment over n years The geometric return is approximately equal to the arithmetic return minus one-half the variance σ^2 of yearly returns, or $r_G \approx r_A - \frac{1}{2}\sigma^2$

Investors can be expected to realize geometric returns only over long periods of time The average geometric return is always less than the average arithmetic return except when all yearly returns are exactly equal This difference is related to the volatility of yearly returns.

A simple example demonstrates the difference If a portfolio falls by 50 percent in the first year and then doubles (up 100 percent) in the second year, "buy and hold" investors are back to where they started, with a total return of zero The compound or geometric return r_G, defined earlier as $(1 - 0\ 5)(1 + 1) - 1$, accurately indicates the zero total return of this investment over the 2 years

The average annual arithmetic return r_A is +25 percent = (–50 percent + 100 percent)/2 Over 2 years, this average return can be turned into a compound or total return only by successfully "timing" the market, specifically increasing the funds invested in the second year and hoping for a recovery in stock prices Had the market dropped again in the second year, this strategy would have been unsuccessful and would have resulted in lower total returns than achieved by the buy-and-hold investor

CHAPTER 2

RISK, RETURN, AND PORTFOLIO ALLOCATION

As a matter of fact, what investment can we find which offers real fixity or certainty income? As every reader of this book will clearly see, the man or woman who invests in bonds is speculating in the general level of prices, or the purchasing power of money

IRVING FISHER, 1912[1]

MEASURING RISK AND RETURN

Risk and return are the building blocks of finance and portfolio management Once the risk and expected return of each asset are specified, modern financial theory can determine the best portfolio for the investor However, the risk and return on stocks and bonds are not physical constants, like the speed of light or gravitational force, waiting to be discovered in the natural world Historical values must be tempered with an appreciation of how investors, attempting to take advantage of the returns from the past, can alter those very returns in the future

[1]Irving Fisher et al , *How to Invest When Prices Are Rising* (Scranton, PA G Lynn Sumner & Co , 1912), p 6

Exhibit JS1-1
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One might question why management would not employ assets in a way to maximize shareholder value, since managers often hold a large equity stake in the firm The reason is that there may exist a conflict between the goal of the shareholders, which is solely to increase the return on the company's shares, and the goals of management, which may include prestige, control of markets, and other objectives Economists recognize the conflict between the goals of managers and shareholders as *agency costs*, and these costs are inherent in every corporate structure where ownership is separated from management Payment of cash dividends or committed share repurchases often lowers management's temptation to pursue goals that do not maximize shareholder value

In recent years dividend yields have fallen to 1½ percent, less than one-third of their historic average The major reasons for this are the tax disadvantage of dividends and the increase in employee stock options, where capital gains and not dividends figure into option value Nevertheless, dividends historically have served the function of showing investors that the firms' earnings were indeed real. Recent concerns about aggressive accounting policies and the integrity of earnings following the Enron debacle may bring back this once-favored way of delivering investor value [9]

DOES THE VALUE OF STOCKS DEPEND ON DIVIDENDS OR EARNINGS?

Management determines its dividend policy—the fraction of earnings it will pay out to shareholders—by evaluating many factors, including the tax differences between dividend income and capital gains, the need to generate internal funds to retire debt or invest, and the desire to keep dividends relatively constant in the face of fluctuating earnings Since the price of a stock depends primarily on the present discounted value of all expected future dividends, it appears that dividend policy is crucial to determining the value of the stock

However, this is not generally true. It does not matter how much is paid as dividends and how much is reinvested *as long as* the firm earns the same return on its retained earnings that shareholders demand on its stock [10] The reason for this is that dividends not paid today are reinvested by the firm and paid as even larger dividends in the future

[9]Jeremy J Siegel, "The Dividend Deficit," *Wall Street Journal*, February 13, 2002, p A20
[10]This ignores differential taxation between capital gains and dividend income that favors reinvestment This is explored in Chapter 4

Of course, management's choice of dividend payout ratio, which is the ratio of cash dividends to total earnings, does influence the timing of the dividend payments The lower the dividend payout ratio, the smaller the dividends will be in the near future Over time, however, dividends will rise and eventually will exceed the dividend path associated with a higher payout ratio Moreover, assuming that the firm earns the same return on investment as the investors require from its equity, the present value of these dividend streams will be identical no matter what payout ratio is chosen

Note that the price of the stock is always equal to the present value of all future *dividends* and not the present value of future earnings Earnings not paid to investors can have value only if they are paid as dividends or other cash disbursements at a later date Valuing stock as the present discounted value of future earnings is manifestly wrong and greatly overstates the value of a firm [11]

John Burr Williams, one of the greatest investment analysts of the early part of last century and author of the classic *The Theory of Investment Value*, argued this point persuasively in 1938 He wrote

> Most people will object at once to the foregoing formula for valuing stocks by saying that it should use the present worth of future earnings, not future dividends But should not earnings and dividends both give the same answer under the implicit assumptions of our critics? If earnings not paid out in dividends are all successfully reinvested at compound interest for the benefit of the stockholder, as the critics imply, then these earnings should produce dividends later, if not, then they are money lost Earnings are only a means to an end, and the means should not be mistaken for the end [12]

LONG-TERM EARNINGS GROWTH AND ECONOMIC GROWTH

Since stock prices are the present value of future dividends, it would seem natural to assume that economic growth would be an important factor influencing future dividends and hence stock prices However, this is not necessarily so The determinants of stock prices are earnings and dividends on a *per-share* basis Although economic growth may influence *aggregate* earnings and dividends favorably, economic growth does not necessarily increase the growth of per-share earnings or dividends It is earnings per share (EPS) that is important to Wall Street be-

[11]Firms that pay no dividends, such as Warren Buffett's Berkshire Hathaway, have value because their assets, which earn cash returns, can be liquidated and disbursed to shareholders in the future
[12]John Burr Williams, *The Theory of Investment Value* (Cambridge, MA Harvard University Press, 1938), p 30

Exhibit JST-1
Page 11

cause per-share data, not aggregate earnings or dividends, are the basis of investor returns

The reason that economic growth does not necessarily increase EPS is because economic growth requires increased capital expenditures and this capital does not come freely Implementing and upgrading technology requires substantial firm investment These expenditures must be funded either by borrowing in the debt market (through banks or trade credit or by selling bonds) or by floating new shares. The added interest costs and the dilution of profits that this funding involves place a burden on the firm's bottom line

Can earnings increase without increasing capital expenditures? In the short run, this may occur, but the long-run historical evidence suggests that it will not One of the signal characteristics of long-term historical data is that the level of the capital stock—the total value of all physical capital such as factories and equipment, as well as intellectual capital, that has accumulated over time—has grown in proportion to the level of aggregate output. In other words, a 10 percent increase in output requires a 10 percent increase in the capital stock

Many investors believe that investment in productivity-enhancing technology can spur earnings growth to permanently higher levels However, "cost-saving investments," frequently touted as a source of increasing profit margins, only temporarily affect bottom-line earnings As long as these investments are available to other firms, competition will force management to reduce product prices by the amount of the cost savings, and extra profits will quickly be competed away In fact, capital expenditures often are undertaken not necessarily to *enhance* profits but rather to *preserve* profits when other firms have adopted competitive cost-saving measures

Table 6-1 shows the summary statistics for dividends per share, earnings per share (EPS), and stock returns from 1871 through September 2001 The data show that real per-share earnings growth over the entire 130 years has been a paltry 1 25 percent, considerably below the nearly 4 percent growth rate of real gross domestic product (GDP) Because of the funding requirement, EPS growth does not match aggregate economic growth over the long run

TABLE 6-1

Long-Term Growth of GDP, Earnings, and Dividends, 1871–2001

	Real GDP Growth	Real Per-Share Earnings Growth	Real Per-Share Dividend Growth	Dividend Yield*	Payout Ratio*
1871-2001	3.91%	1.25%	1.09%	4.54%	58.75%
1871-1945	4.51%	0.66%	0.74%	5.07%	66.78%
1946-2001	3.11%	2.05%	1.56%	3.53%	51.91%

* Denotes median.

The data also show that the acceleration of earnings growth since World War II is associated with the drop in the dividend yield Greater retained earnings allow firms to buy back shares and reinvest for growth John Williams' contention that dividends withheld today spur earnings growth in the future is strongly supported by the data

HISTORICAL YARDSTICKS FOR VALUING THE MARKET

Many yardsticks have been used to evaluate whether stock prices are overvalued or undervalued Most of these measure the market value of the shares outstanding relative to economic *fundamentals* such as earnings, dividends, book value, or some economic aggregate, such as GDP or total replacement cost of the capital stock Stock prices often are said to be "too high" if they exceed the average value over time

Yet such a comparison begs the question Have the historical valuation measures been consistent with the return shareholders should expect from equities? As indicated in Chapters 2 and 3, there is strong evidence that stocks have provided investors excessive returns based on their long-term risk-return profile, suggesting that, on average, they have been undervalued throughout history Therefore, higher valuations could be justified as investors recognize the superior returns on stocks and bid their prices up relative to earnings or dividends

The Price-to-Earnings Ratio

The most basic and fundamental yardstick for valuing stocks is the *price-earnings (P-E) ratio* The P-E ratio is simply the ratio of the price of a share of stock to the annual EPS and measures how much an investor is willing to pay for a dollar's worth of current earnings

The single most important variable determining the P-E ratio of an individual stock is the expectation of future earnings growth If investors believe that earnings growth is going to accelerate, they will pay a higher price relative to current earnings than if they expect earnings to stagnate or decline However, earnings growth is not the only variable influencing the P-E ratio P-E ratios are also influenced by other factors, such as interest rates, risk attitudes of investors, taxes, and liquidity, among others

Exhibit JST-1
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scounted Cash Flow Analys..
Forward Dividend Yield and M/B Ratios
Electric Utility Industry

	Company	Div(1)Yld	M/B
1	Alliant Energy	4 01%	1 23
2	Ameren Corp	5 82%	1 59
3	Avista Corp.	3.09%	1.07
4	Black Hills Corp	4 32%	1.33
5	Central Vermont Public Service	4 67%	1 12
6	CH Energy Group	4 80%	1 45
7	Cinergy Corp	5 06%	1 77
8	Cleco Corp.	5 15%	1 71
9	Consolidated Edison	5.92%	1 32
10	Dominion Resources	4.08%	1 87
11	DPL, Inc.	4.98%	2.85
12	DTE Energy Company	5 23%	1 24
13	Energy East Corp.	4 64%	1 29
14	Entergy Corporation	3.50%	1.37
15	FPL Group, Inc.	3 97%	1 62
16	FirstEnergy Corporation	3.95%	1.49
17	Great Plains Energy, Inc.	5.51%	2.14
18	Hawaiian Electric Industries, Inc	2.57%	3.35
19	IDACORP, Inc	4.35%	1 21
20	MGE Energy, Inc	4.41%	2.10
21	NiSource, Inc	4.59%	1 18
22	NSTAR	4 81%	1.78
23	OGE Energy Corp.	5.51%	1 73
24	Otter Tail Corporation	4 31%	1 94
25	Pinnacle West Capital Corp.	4.71%	1 26
26	PNM Resources	3 20%	1.10
27	Public Service Enterprise Group, Inc	5.30%	1 99
28	Puget Energy, Inc.	4.73%	1 25
29	SCANA Corp.	4.25%	1 64
30	The Empire District Electric Co.	6.32%	1.33
31	The Southern Company	4 91%	2 17
32	Wisconsin Energy	2 78%	1 50
	Mean	4 55%	1 62
	Median	4 66%	1 49
	Std. Deviation	0.87%	0.50
	Maximum value	6 32%	3 35
	Minimum value	2.57%	1 07
	1st Quartile	4.06%	1 25
	3rd Quartile	5.08%	1 80

Multi-Stage DCF Cost of Equity Analysis
Electric Utility Industry

		Stock Price	First Stage	Near-Term Stage				Long-Term Growth Rate	IRR Cost of Equity
			d_1	d_2	d_3	d_4			
1	Alliant Energy	$ (24 95)	$ 1 00	$ 1 06	$ 1 11	$ 1 18		3 0%	7 29%
2	Ameren Corp	$ (43 67)	$ 2 54	$ 2 54	$ 2 54	$ 2 54		3 0%	8 37%
3	Avista Corp	$ (16 84)	$ 0 52	$ 0 56	$ 0 61	$ 0 66		3 0%	6 55%
4	Black Hills Corp	$ (29 20)	$ 1 26	$ 1 30	$ 1 34	$ 1 38		3 0%	7 32%
5	Central Vermont Public Service	$ (19 90)	$ 0 93	$ 0 97	$ 1 01	$ 1 05		3 0%	7 81%
6	CH Energy Group	$ (44 99)	$ 2 16	$ 2 16	$ 2 16	$ 2 16		3 0%	7 43%
7	Cinergy Corp	$ (37 36)	$ 1 89	$ 1 93	$ 1 97	$ 2 01		3 0%	7 93%
8	Cleco Corp	$ (17 47)	$ 0 90	$ 0 90	$ 0 90	$ 0 90		3 0%	7 75%
9	Consolidated Edison	$ (38 37)	$ 2 27	$ 2 29	$ 2 31	$ 2 33		3 0%	8 59%
10	Dominion Resources	$ (63 30)	$ 2 58	$ 2 66	$ 2 74	$ 2 82		3 0%	7 07%
11	DPL, Inc	$ (19 48)	$ 0 97	$ 0 99	$ 1 01	$ 1 03		3 0%	7 85%
12	DTE Energy Company	$ (39 38)	$ 2 06	$ 2 07	$ 2 08	$ 2 09		3 0%	7 89%
13	Energy East Corp	$ (22 64)	$ 1 05	$ 1 09	$ 1 13	$ 1 17		3 0%	7 72%
14	Entergy Corporation	$ (53 09)	$ 1 86	$ 1 94	$ 2 02	$ 2 10		3 0%	6 61%
15	FPL Group, Inc	$ (62 90)	$ 2 50	$ 2 58	$ 2 66	$ 2 74		3 0%	6 98%
16	FirstEnergy Corporation	$ (38 00)	$ 1 50	$ 1 55	$ 1 60	$ 1 65		3 0%	6 97%
17	Great Plains Energy, Inc	$ (30 13)	$ 1 66	$ 1 69	$ 1 73	$ 1 76		3 0%	8 37%
18	Hawaiian Electric Industries, Inc	$ (48 17)	$ 1 24	$ 1 25	$ 1 27	$ 1 28		3 0%	5 44%
19	IDACORP, Inc	$ (27 58)	$ 1 20	$ 1 20	$ 1 20	$ 1 20		3 0%	7 01%
20	MGE Energy, Inc	$ (30 60)	$ 1 35	$ 1 36	$ 1 37	$ 1 38		3 0%	7 15%
21	NiSource, Inc	$ (20 24)	$ 0 93	$ 0 96	$ 0 99	$ 1 03		3 0%	7 64%
22	NSTAR	$ (46 60)	$ 2 24	$ 2 30	$ 2 37	$ 2 43		3 0%	7 78%
23	OGE Energy Corp	$ (24 14)	$ 1 33	$ 1 35	$ 1 36	$ 1 38		3 0%	8 26%
24	Otter Tail Corporation	$ (25 76)	$ 1 11	$ 1 13	$ 1 15	$ 1 17		3 0%	7 17%
25	Pinnacle West Capital Corp	$ (39 31)	$ 1 85	$ 1 93	$ 2 01	$ 2 09		3 0%	7 85%
26	PNM Resources	$ (29 96)	$ 0 96	$ 1 00	$ 1 04	$ 1 08		3 0%	6 29%
27	Public Service Enterprise Group, Inc	$ (41 67)	$ 2 21	$ 2 25	$ 2 29	$ 2 33		3 0%	8 13%
28	Puget Energy, Inc	$ (21 14)	$ 1 00	$ 1 04	$ 1 08	$ 1 12		3 0%	7 83%
29	SCANA Corp	$ (34 80)	$ 1 48	$ 1 56	$ 1 63	$ 1 72		3 0%	7 49%
30	The Empire District Electric Co	$ (20 24)	$ 1 28	$ 1 28	$ 1 28	$ 1 28		3 0%	8 84%
31	The Southern Company	$ (28 90)	$ 1 42	$ 1 47	$ 1 53	$ 1 58		3 0%	8 00%
32	Wisconsin Energy	$ (30 60)	$ 0 85	$ 0 89	$ 0 93	$ 0 98		3 0%	5 91%

Mean (rounded to three decimal places)	**7.50%**
Median	7 68%
Std Deviation	0 75%
Maximum value	8 84%
Minimum value	5 44%
1st Quartile	7 06%
3rd Quartile	7 90%

Multi-Stage DCF Cost of Equity Analysis
Electric Utility Industry

		Stock Price	First Stage	Near-Term Stage			Long-Term Growth Rate	IRR Cost of Equity
			d_1	d_2	d_3	d_4		
1	Alliant Energy	$ (24 95)	$ 1 00	$ 1 06	$ 1 11	$ 1 18	4 0%	8 17%
2	Ameren Corp	$ (43 67)	$ 2 54	$ 2 54	$ 2 54	$ 2 54	4 0%	9 23%
3	Avista Corp	$ (16 84)	$ 0 52	$ 0 56	$ 0 61	$ 0 66	4 0%	7 45%
4	Black Hills Corp	$ (29 20)	$ 1 26	$ 1 30	$ 1 34	$ 1 38	4 0%	8 21%
5	Central Vermont Public Service	$ (19 90)	$ 0 93	$ 0 97	$ 1 01	$ 1 05	4 0%	8 68%
6	CH Energy Group	$ (44 99)	$ 2 16	$ 2 16	$ 2 16	$ 2 16	4 0%	8 31%
7	Cinergy Corp	$ (37 36)	$ 1 89	$ 1 93	$ 1 97	$ 2 01	4 0%	8 81%
8	Cleco Corp	$ (17 47)	$ 0 90	$ 0 90	$ 0 90	$ 0 90	4 0%	8 63%
9	Consolidated Edison	$ (38 37)	$ 2 27	$ 2 29	$ 2 31	$ 2 33	4 0%	9 45%
10	Dominion Resources	$ (63 30)	$ 2 58	$ 2 66	$ 2 74	$ 2 82	4 0%	7 96%
11	DPL, Inc	$ (19 48)	$ 0 97	$ 0 99	$ 1 01	$ 1 03	4 0%	8 72%
12	DTE Energy Company	$ (39 38)	$ 2 06	$ 2 07	$ 2 08	$ 2 09	4 0%	8 76%
13	Energy East Corp	$ (22 64)	$ 1 05	$ 1 09	$ 1 13	$ 1 17	4 0%	8 59%
14	Entergy Corporation	$ (53 09)	$ 1 86	$ 1 94	$ 2 02	$ 2 10	4 0%	7 51%
15	FPL Group, Inc	$ (62 90)	$ 2 50	$ 2 58	$ 2 66	$ 2 74	4 0%	7 88%
16	FirstEnergy Corporation	$ (38 00)	$ 1 50	$ 1 55	$ 1 60	$ 1 65	4 0%	7 86%
17	Great Plains Energy, Inc	$ (30 13)	$ 1 66	$ 1 69	$ 1 73	$ 1 76	4 0%	9 23%
18	Hawaiian Electric Industries, Inc	$ (48 17)	$ 1 24	$ 1 25	$ 1 27	$ 1 28	4 0%	6 37%
19	IDACORP, Inc	$ (27 58)	$ 1 20	$ 1 20	$ 1 20	$ 1 20	4 0%	7 90%
20	MGE Energy, Inc	$ (30 60)	$ 1 35	$ 1 36	$ 1 37	$ 1 38	4 0%	8 04%
21	NiSource, Inc	$ (20 24)	$ 0 93	$ 0 96	$ 0 99	$ 1 03	4 0%	8 52%
22	NSTAR	$ (46 60)	$ 2 24	$ 2 30	$ 2 37	$ 2 43	4 0%	8 65%
23	OGE Energy Corp	$ (24 14)	$ 1 33	$ 1 35	$ 1 36	$ 1 38	4 0%	9 13%
24	Otter Tail Corporation	$ (25 76)	$ 1 11	$ 1 13	$ 1 15	$ 1 17	4 0%	8 06%
25	Pinnacle West Capital Corp	$ (39 31)	$ 1 85	$ 1 93	$ 2 01	$ 2 09	4 0%	8 72%
26	PNM Resources	$ (29 96)	$ 0 96	$ 1 00	$ 1 04	$ 1 08	4 0%	7 20%
27	Public Service Enterprise Group, Inc	$ (41 67)	$ 2 21	$ 2 25	$ 2 29	$ 2 33	4 0%	9 00%
28	Puget Energy, Inc	$ (21 14)	$ 1 00	$ 1 04	$ 1 08	$ 1 12	4 0%	8 70%
29	SCANA Corp	$ (34 80)	$ 1 48	$ 1 56	$ 1 63	$ 1 72	4 0%	8 38%
30	The Empire District Electric Co	$ (20 24)	$ 1 28	$ 1 28	$ 1 28	$ 1 28	4 0%	9 69%
31	The Southern Company	$ (28 90)	$ 1 42	$ 1 47	$ 1 53	$ 1 58	4 0%	8 87%
32	Wisconsin Energy	$ (30 60)	$ 0 85	$ 0 89	$ 0 93	$ 0 98	4 0%	6 83%

Mean (rounded to three decimal places)	**8.40%**
Median	8 56%
Std Deviation	0 73%
Maximum value	9 69%
Minimum value	6 37%
1st Quartile	7 95%
3rd Quartile	8 77%

Multi-Stage DCF Cost of Equity Analysis
Electric Utility Industry

		Stock Price	First Stage	Near-Term Stage			Long-Term Growth Rate	IRR Cost of Equity
			d_1	d_2	d_3	d_4		
1	Alliant Energy	$ (24 95)	$ 1 00	$ 1 06	$ 1 11	$ 1 18	5 0%	9 06%
2	Ameren Corp	$ (43 67)	$ 2 54	$ 2.54	$ 2 54	$ 2 54	5 0%	10 09%
3	Avista Corp	$ (16 84)	$ 0 52	$ 0 56	$ 0 61	$ 0 66	5 0%	8 36%
4	Black Hills Corp	$ (29 20)	$ 1 26	$ 1 30	$ 1 34	$ 1 38	5 0%	9 10%
5	Central Vermont Public Service	$ (19 90)	$ 0 93	$ 0 97	$ 1 01	$ 1 05	5 0%	9 56%
6	CH Energy Group	$ (44 99)	$ 2 16	$ 2 16	$ 2 16	$ 2 16	5 0%	9 20%
7	Cinergy Corp	$ (37 36)	$ 1 89	$ 1 93	$ 1 97	$ 2 01	5 0%	9 68%
8	Cleco Corp	$ (17 47)	$ 0 90	$ 0 90	$ 0 90	$ 0 90	5 0%	9 51%
9	Consolidated Edison	$ (38 37)	$ 2 27	$ 2 29	$ 2 31	$ 2 33	5 0%	10 31%
10	Dominion Resources	$ (63 30)	$ 2 58	$ 2 66	$ 2 74	$ 2 82	5 0%	8 86%
11	DPL, Inc	$ (19 48)	$ 0 97	$ 0 99	$ 1 01	$ 1 03	5 0%	9 60%
12	DTE Energy Company	$ (39 38)	$ 2 06	$ 2 07	$ 2 08	$ 2 09	5 0%	9 64%
13	Energy East Corp	$ (22 64)	$ 1 05	$ 1 09	$ 1 13	$ 1 17	5 0%	9 47%
14	Entergy Corporation	$ (53 09)	$ 1 86	$ 1 94	$ 2 02	$ 2 10	5 0%	8 42%
15	FPL Group, Inc	$ (62 90)	$ 2 50	$ 2 58	$ 2 66	$ 2 74	5 0%	8 77%
16	FirstEnergy Corporation	$ (38 00)	$ 1 50	$ 1 55	$ 1 60	$ 1 65	5 0%	8.76%
17	Great Plains Energy, Inc	$ (30 13)	$ 1 66	$ 1 69	$ 1 73	$ 1 76	5 0%	10 10%
18	Hawaiian Electric Industries, Inc	$ (48 17)	$ 1 24	$ 1 25	$ 1 27	$ 1 28	5 0%	7 30%
19	IDACORP, Inc	$ (27 58)	$ 1 20	$ 1 20	$ 1 20	$ 1 20	5 0%	8 80%
20	MGE Energy, Inc	$ (30 60)	$ 1 35	$ 1 36	$ 1 37	$ 1 38	5 0%	8 93%
21	NiSource, Inc	$ (20 24)	$ 0 93	$ 0 96	$ 0 99	$ 1 03	5 0%	9 40%
22	NSTAR	$ (46 60)	$ 2 24	$ 2 30	$ 2 37	$ 2 43	5 0%	9 53%
23	OGE Energy Corp	$ (24 14)	$ 1 33	$ 1 35	$ 1 36	$ 1 38	5 0%	10 00%
24	Otter Tail Corporation	$ (25 76)	$ 1 11	$ 1 13	$ 1 15	$ 1 17	5 0%	8 95%
25	Pinnacle West Capital Corp	$ (39 31)	$ 1 85	$ 1 93	$ 2 01	$ 2 09	5 0%	9 60%
26	PNM Resources	$ (29 96)	$ 0 96	$ 1 00	$ 1 04	$ 1 08	5 0%	8 11%
27	Public Service Enterprise Group, Inc	$ (41 67)	$ 2 21	$ 2 25	$ 2 29	$ 2 33	5 0%	9 87%
28	Puget Energy, Inc	$ (21 14)	$ 1 00	$ 1 04	$ 1 08	$ 1 12	5 0%	9 58%
29	SCANA Corp	$ (34 80)	$ 1 48	$ 1 56	$ 1 63	$ 1 72	5 0%	9 26%
30	The Empire District Electric Co	$ (20 24)	$ 1 28	$ 1 28	$ 1 28	$ 1 28	5 0%	10 55%
31	The Southern Company	$ (28 90)	$ 1 42	$ 1 47	$ 1 53	$ 1 58	5 0%	9 74%
32	Wisconsin Energy	$ (30 60)	$ 0 85	$ 0 89	$ 0 93	$ 0 98	5 0%	7 76%

Mean (rounded to three decimal places)	**9.20%**
Median	9 44%
Std Deviation	0 71%
Maximum value	10 55%
Minimum value	7 30%
1st Quartile	8 84%
3rd Quartile	9 65%

Treasury Bonds, Notes and Bills

May 25, 2004

Explanatory Notes

Representative Over the-Counter quotation based on transactions of $1 million or more Treasury bond note and bill quotes are as of mid afternoon Colons in bid and asked quotes represent 32nds 101 01 means 101 1/32 Net changes in 32nds n Treasury note i Inflation-Indexed issue Treasury bill quotes in hundredths, quoted on terms of a rate of discount Days to maturity calculated from settlement date All yields are to maturity and based on the asked quote Latest 13 week and 26 week bills are boldfaced For bonds callable prior to maturity, yields are computed to the earliest call date for issues quoted above par and to the maturity date for issues below par *When issued

Source eSpeed/Cantor Fitzgerald

U S Treasury strips as of 3 p m Eastern time also based on transactions of $1 million or more Colons in bid and asked quotes represent 32nds 99 01 means 99 1/32 Net changes in 32nds Yields calculated on the asked quotation ci stripped coupon interest. bp Treasury bond stripped principal np Treasury note stripped principal For bonds callable prior to maturity yields are computed to the earliest call date for issues quoted above par and to the maturity date for issues below par

Source Bear Stearns & Co via Street Software Technology Inc

Government Bonds & Notes

RATE	MATURITY MO/YR	BID	ASKED	CHG	ASK YLD
3.250	May 04n	100-00	100-01	-1	0.18
2.875	Jun 04n	100-05	100-06	-1	0.75
2.250	Jul 04n	100-06	100-07	-1	0.95
2.125	Aug 04n	100-08	100-09	-1	0.99
6.000	Aug 04n	101-03	101-04		0.92
7.250	Aug 04n	101.12	101.13	..	0.98
13.750	Aug 04	102.25	102.26	-1	0.98
1.875	Sep 04n	100-07	100-08	-1	1.10
2.125	Oct 04n	100-10	100-11		1.28
5.875	Nov 04n	102-02	102-03	-1	1.36
7.875	Nov 04n	103-00	103-01	-1	1.35
11.625	Nov 04	104.25	104.26		1.32
2.000	Nov 04n	100-09	100.10		1.36
1.750	Dec 04n	100-04	100-05	-1	1.46
1.625	Jan 05n	100-01	100-02		1.51
7.500	Feb 05n	104-06	104-07	-1	1.58
1.500	Feb 05n	99.29	99.30		1.58
1.625	Mar 05n	99.29	99.30	-1	1.68
1.625	Apr 05n	99.27	99.28		1.76
6.500	May 05n	104.15	104.16		1.78
6.750	May 05n	104.22	104.23	-1	1.80
12.000	May 05	109.26	109.27		1.72
1.250	May 05n	99.14	99.15	..	1.78
1.125	Jun 05n	99-05	99-06	-1	1.86
1.500	Jul 05n	99-14	99.15	..	1.96
6.500	Aug 05n	105.12	105.13	-1	1.99
10.750	Aug 05	110.16	110.17	-1	1.97
2.000	Aug 05n	99.30	99-31		2.02
1.625	Sep 05n	99.11	99.12	-1	2.09
1.625	Oct 05n	99-07	99-08		2.16
5.750	Nov 05n	105-02	105-03	-1	2.21
5.875	Nov 05n	105-08	105-09		2.20
1.875	Nov 05n	99-13	99-14		2.24
1.875	Dec 05n	99-08	99-09		2.33
1.875	Jan 06n	99.05	99-06	..	2.37
5.625	Feb 06n	105.15	105.16	..	2.35
9.375	Feb 06	111.23	111.24	..	2.36
1.625	Feb 06n	98.19	98.20	..	2.43
1.500	Mar 06n	98-07	98-08		2.47
2.250	Apr 06n	99.14	99.15	..	2.53
2.000	May 06n	98.29	98.30		2.56
4.625	May 06n	103.29	103.30		2.56
6.875	May 06n	108-07	108-08		2.55
7.000	Jul 06n	108.28	108.29		2.68
2.375	Aug 06n	99.07	99-08	1	2.72
6.500	Oct 06n	108.12	108-13		2.83
2.625	Nov 06n	99.11	99.12		2.89
3.500	Nov 06n	101.13	101.14		2.89
3.375	Jan 07i	107.26	107.27	-3	0.38
2.250	Feb 07n	98.00	98.01		3.00
6.250	Feb 07n	108.12	108.13		3.00
6.625	May 07n	109.25	109.26		3.13
4.375	May 07n	103.14	103.15		3.14
3.125	May 07n	99.29	99.30	..	3.14
3.250	Aug 07n	100-01	100-02		3.23
6.125	Aug 07n	108.23	108.24		3.24
3.000	Nov 07n	98.29	98.30	..	3.33
3.625	Jan 08i	110-01	110-02	-4	0.81
3.000	Feb 08n	98.13	98.14	1	3.45
5.500	Feb 08n	107-03	107-04		3.44
2.625	May 08n	96.16	96.17	1	3.57
5.625	May 08n	107.18	107.19	1	3.56
3.250	Aug 08n	98.14	98.15	1	3.64
3.125	Sep 08n	97.24	97.25	1	3.69
3.125	Oct 08n	97.18	97.19	1	3.72
3.375	Nov 08n	98.15	98.16	2	3.74
4.750	Nov 08n	104-04	104-05	1	3.73
3.375	Dec 08n	98-08	98-09	1	3.79
3.250	Jan 09n	97.18	97.19	1	3.82
3.875	Jan 09i	112-02	112-03	-6	1.18
3.000	Feb 09n	96.12	96.13		3.83
2.625	Mar 09n	94.21	94.22	1	3.85
3.125	Apr 09n	96.24	96.25	1	3.85
3.875	May 09n	99.30	99.31	1	3.88
5.500	May 09n	107.13	107.14	2	3.84
6.000	Aug 09n	109.18	109.19	1	3.95
10.375	Nov 09	104-06	104.07	..	1.34
4.250	Jan 10i	115-01	115-02	-6	1.45
6.500	Feb 10n	112-07	112-08		4.07
11.750	Feb 10	107-07	107-08		1.61
10.000	May 10	107.25	107.26		1.84
5.750	Aug 10n	108-14	108.15	1	4.19
12.750	Nov 10	115-02	115-03	2	2.25
3.500	Jan 11i	111.15	111.16	-5	1.66
5.000	Feb 11n	104-01	104-02	2	4.29
13.875	May 11	121.19	121.20	-1	2.55
5.000	Aug 11n	103.21	103.22	2	4.40
14.000	Nov 11	126.13	126.14	1	2.84
3.375	Jan 12i	111-08	111.09	-4	1.79
4.875	Feb 12n	102.15	102.16	3	4.49
3.000	Jul 12i	108.18	108.19	-4	1.86
4.375	Aug 12n	98.22	98.23	3	4.56
4.000	Nov 12n	95.28	95.29	2	4.59
10.375	Nov 12	122.23	122.24	..	3.37
3.875	Feb 13n	94.21	94.22	3	4.62
3.625	May 13n	92.25	92.26	3	4.61
1.875	Jul 13i	99-09	99.10	-4	1.96
4.250	Aug 13n	96.19	96.20	2	4.70
12.000	Aug 13	132.16	132.17	3	3.62
4.250	Nov 13n	96.11	96.12	4	4.73
2.000	Jan 14i	100-00	100-00	-6	2.00
4.000	Feb 14n	94.16	94.17	3	4.70
4.750	May 14n	100-04	100-05	2	4.73
13.250	May 14	142-05	142-06	5	3.84
12.500	Aug 14	140.03	140.04	5	3.92
11.750	Nov 14	137.21	137.22	5	4.01
11.250	Feb 15	153.08	153-09	4	4.82
10.625	Aug 15	149-02	149-03	5	4.89
9.875	Nov 15	142.25	142.26	5	4.94
9.250	Feb 16	137.18	137.19	5	4.98
7.250	May 16	119.22	119.23	5	5.03
7.500	Nov 16	122-01	122-02	5	5.09
8.750	May 17	134-07	134-08	6	5.11
8.875	Aug 17	135-20	135.21	5	5.13
9.125	May 18	138.28	138.29	4	5.18
9.000	Nov 18	138.03	138.04	7	5.21
8.875	Feb 19	136.25	136.26	6	5.25
8.125	Aug 19	129-14	129-15	6	5.28
8.500	Feb 20	133.24	133.25	5	5.30
8.750	May 20	136.25	136.26	6	5.30
8.750	Aug 20	137-00	137-01	7	5.31
7.875	Feb 21	127.18	127.19	7	5.35
8.125	May 21	130-19	130.20	6	5.35
8.125	Aug 21	130.24	130-25	7	5.36
8.000	Nov 21	129.16	129-17	7	5.37
7.250	Aug 22	120-30	120-31	7	5.42
7.625	Nov 22	125.17	125.18	8	5.42
7.125	Feb 23	119-20	119.21	8	5.44
6.250	Aug 23	109-05	109.06	7	5.47
7.500	Nov 24	124.30	124.31	7	5.46
7.625	Feb 25	126.18	126.19	8	5.46
6.875	Aug 25	117-07	117.08	7	5.49
6.000	Feb 26	106-07	106.08	8	5.50
6.750	Aug 26	115.30	115.31	9	5.50
6.500	Nov 26	112-23	112-24	8	5.50
6.625	Feb 27	114.13	114.14	8	5.50
6.375	Aug 27	111.08	111.09	9	5.51
6.125	Nov 27	108.01	108.02	9	5.51
3.625	Apr 28i	122-01	122.02	-10	2.41
5.500	Aug 28	99.26	99.27	8	5.51
5.250	Nov 28	96.17	96.18	9	5.51
5.250	Feb 29	96.19	96.20	8	5.50
3.875	Apr 29i	127-17	127.18	-11	2.40
6.125	Aug 29	108-12	108.13	7	5.50
6.250	May 30	110-11	110.12	10	5.50
5.375	Feb 31	99-13	99.14	10	5.41
3.375	Apr 32i	121.27	121.28	-11	2.31

U.S. Treasury Strips

MATURITY	TYPE	BID	ASKED	CHG	ASK YLD
Jul 04	ci	99-27	99-27	..	1.07
Aug 04	ci	99.25	99.25	..	0.98
Aug 04	np	99.25	99.25	..	0.98
Nov 04	ci	99-12	99.12	...	1.33
Nov 04	bp	99-12	99.12	..	1.36
Nov 04	np	99-12	99.12	..	1.36
Jan 05	ci	99-09	99-09	..	1.14
Feb 05	ci	98.28	98.28	..	1.56
Feb 05	np	98.28	98.28	..	1.58
May 05	ci	98.10	98.10	..	1.78
May 05	bp	98-09	98.09		1.79
May 05	np	98.09	98-09		1.80
May 05	np	98-09	98-09		1.80
Jul 05	ci	98-09	98-09	...	1.54
Aug 05	ci	97.21	97.21		1.96
Aug 05	bp	97.18	97.18	...	2.02
Aug 05	np	97.19	97.19		2.01
Nov 05	ci	96.27	96.27	1	2.19
Nov 05	np	96.26	96.26	..	2.22
Nov 05	np	96.26	96.26		2.23
Jan 06	ci	96.23	96.23	2	2.05
Feb 06	ci	95.28	95.28	1	2.46
Feb 06	bp	96.00	96.00	1	2.40
Feb 06	np	96.00	96.00	1	2.38
May 06	ci	95.02	95.02	1	2.59
May 06	np	95.01	95.01	1	2.60
May 06	np	95.03	95.03	1	2.57
Jul 06	ci	95.07	95.07	2	2.31
Jul 06	np	94.14	94.14	1	2.70
Aug 06	ci	94.06	94.06	2	2.71
Aug 06	np	94.04	94.04	1	2.75
Oct 06	np	93.14	93.14	1	2.86
Nov 06	ci	93.08	93.08	2	2.86
Nov 06	np	93.03	93.03		2.92
Nov 06	np	93.04	93.04	1	2.91
Feb 07	ci	91.31	91.31	1	3.10
Feb 07	np	92.02	92.02	1	3.06
May 07	ci	91.00	91.00	1	3.20
May 07	np	91.00	91.00	1	3.20
May 07	np	91.03	91.03	1	3.16
Aug 07	ci	89.29	89.29	1	3.34
Aug 07	np	89.31	89.31	1	3.31
Aug 07	np	90.03	90.03	1	3.27
Nov 07	ci	89.00	89.00	3	3.39
Nov 07	np	89.02	89.02	1	3.37
Feb 08	ci	87.25	87.25	1	3.53
Feb 08	np	87.28	87.28	1	3.51
Feb 08	np	87.30	87.30	1	3.49
May 08	ci	86.19	86.19	1	3.66
May 08	np	86.23	86.23	1	3.63
Aug 08	ci	85.19	85.19	1	3.72
Aug 08	np	85.21	85.21	2	3.70
May 08	np	86.26	86.26	1	3.60
Nov 08	ci	84.11	84.11	2	3.85
Nov 08	np	84.16	84.16	2	3.81
Nov 08	np	84.16	84.16	2	3.81
Feb 09	ci	83.05	83.05	2	3.95
Feb 09	np	83.12	83.12	2	3.89
May 09	ci	82.01	82.01	2	4.03
May 09	np	82.13	82.13	2	3.93
May 09	np	82.11	82.11	2	3.95
Aug 09	ci	80.31	80.31	2	4.09
Aug 09	np	81.03	81.03	2	4.05
Nov 09	ci	80.06	80.06	2	4.08
Nov 09	bp	79.16	79.16	2	4.24
Feb 10	ci	78.20	78.20	3	4.25
Feb 10	np	78.29	78.29	4	4.19
May 10	ci	77.19	77.19	2	4.30
Aug 10	ci	76.18	76.18	3	4.34
Aug 10	np	76.24	76.24	4	4.30
Nov 10	ci	75.27	75.27	1	4.32
Feb 11	ci	74.08	74.08	3	4.48
Feb 11	np	74.19	74.19	4	4.41
May 11	ci	73.06	73.06	3	4.53
Aug 11	ci	72.00	72.00	3	4.60
Aug 11	np	72.13	72.13	3	4.52
Nov 11	ci	71.03	71.03	3	4.62
Feb 12	ci	69.26	69.26	3	4.71
Feb 12	np	70.10	70.10	3	4.62
May 12	ci	68.22	68.22	3	4.77
Aug 12	ci	67.18	67.18	3	4.83
Aug 12	np	68.11	68.11	4	4.68
Nov 12	ci	66.17	66.17	3	4.87
Nov 12	np	67.16	67.16	4	4.70
Feb 13	ci	65.18	65.18	4	4.90
Feb 13	np	66.18	66.18	4	4.72
May 13	ci	64.15	64.15	4	4.95
May 13	np	65.28	65.28	1	4.71
Aug 13	ci	63.15	63.15	4	4.99
Aug 13	np	64.14	64.14	4	4.82
Nov 13	ci	62.15	62.15	4	5.03
Nov 13	np	63.15	63.15	4	4.86
Feb 14	ci	61.16	61.16	4	5.07
Feb 14	np	63.00	63.00	4	4.81
May 14	ci	60.15	60.15	4	5.11
May 14	np	61.31	61.31	4	4.86
Aug 14	ci	59.16	59.16	4	5.14
Nov 14	ci	58.18	58.18	4	5.18

Treasury Bills

MATURITY	DAYS TO MAT	BID	ASKED	CHG	ASK YLD
May 27 04	1	0.89	0.88	0.02	0.89
Jun 03 04	8	0.85	0.84	-0.01	0.85
Jun 10 04	15	0.89	0.88	0.01	0.89
Jun 17 04	22	0.92	0.91	0.03	0.92
Jun 24 04	29	0.92	0.91	0.03	0.92
Jul 01 04	36	0.88	0.87	0.02	0.88
Jul 08 04	43	0.89	0.88	0.02	0.89
Jul 15 04	50	0.90	0.89	0.01	0.90
Jul 22 04	57	0.90	0.89	...	0.90
Jul 29 04	64	0.92	0.91	0.01	0.92
Aug 05 04	71	0.96	0.95	0.01	0.97
Aug 12 04	78	0.95	0.94	0.01	0.96
Aug 19 04	85	1.03	1.02	0.01	1.04
Aug 26 04	92	1.06	1.05	0.02	1.07
Sep 02 04	99	1.08	1.07	0.03	1.09
Sep 09 04	106	1.08	1.07	0.02	1.09
Sep 16 04	113	1.10	1.09	0.01	1.11
Sep 23 04	120	1.11	1.10	...	1.12
Sep 30 04	127	1.14	1.13	0.01	1.15
Oct 07 04	134	1.17	1.16	0.01	1.18
Oct 14 04	141	1.22	1.21	0.03	1.23
Oct 21 04	148	1.24	1.23	0.01	1.25
Oct 28 04	155	1.26	1.25	0.01	1.27
Nov 04 04	162	1.29	1.28	0.01	1.31
Nov 12 04	170	1.33	1.32	0.01	1.35
Nov 18 04	176	1.37	1.36	0.02	1.39
Nov 26 04	184	1.38	1.37	...	1.40

Inflation-Indexed Treasury Securities

RATE	MAT	BID/ASKED	CHG	*YLD	ACCR PRIN
3.375	01/07	107-26/27	-3	0.386	1181
3.625	01/08	110-01/02	-4	0.814	1158
3.875	01/09	112-02/03	-6	1.188	1141
4.250	01/10	115-01/02	-6	1.458	1112
3.500	01/11	111-15/16	-5	1.663	1075
3.375	01/12	111-08/09	-4	1.788	1054
3.000	07/12	108-18/19	-4	1.857	1041
1.875	07/13	99-09/10	-4	1.957	1019
2.000	01/14	100-00/00	-6	2.000	1011
3.625	04/28	122-01/02	-10	2.405	1157
3.875	04/29	127-17/18	-11	2.398	1138
3.375	04/32	121-27/28	-11	2.307	1054

*Yield to maturity on accrued principal

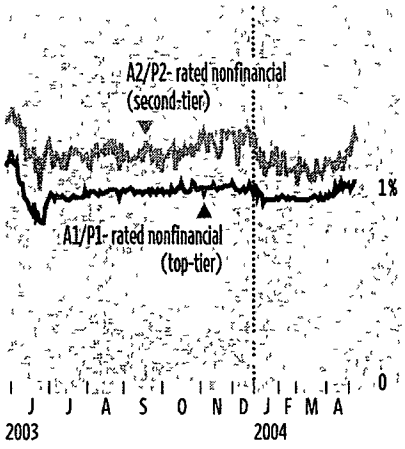
Money Rates

Tuesday, May 25, 2004

The key U S and foreign annual interest rates below are a guide to general levels but don't always represent actual transactions

Commercial Paper

Yields paid by corporations for short-term financing, typically for daily operation



Source Federal Reserve

Prime Rate: 4 00% (effective 06/27/03) The base rate on corporate loans posted by at least 75% of the nation's 30 largest banks

Discount Rate (Primary): 2 00% (effective 06/25/03)

Federal Funds: 1 031% high, 0 969% low, 0 969% near closing bid, 1.000% offered Effective rate 1 00% Source Prebon Yamane (USA) Inc Federal-funds target rate 1 000% (effective 06/25/03)

Call Money. 2.75% (effective 06/30/03).

Commercial Paper: Placed directly by General Electric Capital Corp. 0.80% 30 to 51 days, 1.12% 52 to 83 days, 1.22% 84 to 105 days, 1.31% 106 to 120 days, 0.80% 121 to 132 days, 1 41% 133 to 175 days, 1 50% 176 to 197 days, 1.60% 198 to 231 days; 1 69% 232 to 270 days

Euro Commercial Paper: Placed directly by General Electric Capital Corp 2 01% 30 days, 2 04% two months; 2 05% three months, 2 07% four months, 2 09% five months, 2 11% six months

Dealer Commercial Paper: High-grade unsecured notes sold through dealers by major corporations 1 02% 30 days, 1 10% 60 days, 1 20% 90 days

Certificates of Deposit: 1 05% one month, 1 23% three months, 1 54% six months

Bankers Acceptances: 1.04% 30 days, 1.13% 60 days, 1 23% 90 days, 1 33% 120 days, 1.43% 150 days, 1 51% 180 days Source Prebon Yamane (USA) Inc

Eurodollars: 1.04% - 1 03% one month, 1.14% - 1.12% two months; 1.25% - 1 23% three months, 1 37% - 1 34% four months, 1.47% - 1 43% five months, 1.56% - 1.52% six months Source Prebon Yamane (USA) Inc.

London Interbank Offered Rates (Libor): 1.1000% one month, 1.2900% three months, 1 5825% six months, 2 1000% one year Effective rate for contracts entered into two days from date appearing at top of this column

Euro Libor: 2 06225% one month; 2 09150% three months, 2 14588% six months, 2 32038% one year Effective rate for contracts entered into two days from date appearing at top of this column

Euro Interbank Offered Rates (Euribor): 2.063% one month, 2 092% three months, 2.147% six months, 2.323% one year Source Reuters

Foreign Prime Rates: Canada 3 75%, European Central Bank 2 00%; Japan 1.375%, Switzerland 2 14%, Britain 4.25%

Treasury Bills: Results of the Monday, May 24, 2004, auction of short-term U S government bills, sold at a discount from face value in units of $1,000 to $1 million: 1 050% 13 weeks, 1.375% 26 weeks Tuesday, May 25, 2004 auction: 0 910% 4 weeks.

Overnight Repurchase Rate. 0 96%. Source. Garban Intercapital

Freddie Mac: Posted yields on 30-year mortgage commitments Delivery within 30 days 6 05%, 60 days 6 12%, standard conventional fixed-rate mortgages. 2 875%, 2% rate capped one-year adjustable rate mortgages.

Fannie Mae: Posted yields on 30 year mortgage commitments (priced at par) for delivery within 30 days 6 08%, 60 days 6 16%, standard conventional fixed-rate mortgages, 3 35%, 6/2 rate capped one-year adjustable rate mortgages Constant Maturity Debt Index 1 202% three months, 1.525% six months, 2.030% one year

Merrill Lynch Ready Assets Trust: 0 51%

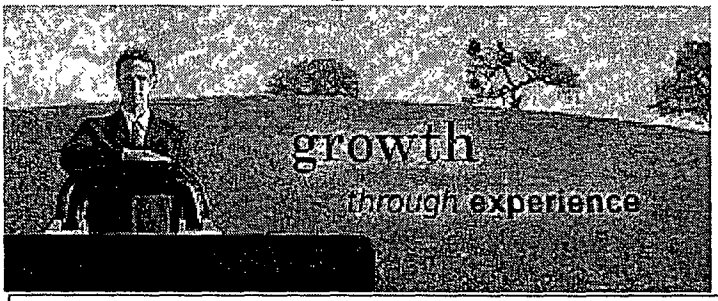
Consumer Price Index: April, 188 0, up 2 3% from a year ago. Bureau of Labor Statistics.

Capital Structures and Beta
Sample Electric Utility Companies

	Company	2003 Equity %	V-L Equity Beta	Raw V-L Beta	10% TO 1.0 Adjusted V-L Beta	Unlevered Raw Asset Beta
1	Alliant Energy	49%	0 75	0 60	0 64	0 36
2	Ameren Corp	50%	0 70	0 52	0 57	0 32
3	Avista Corp	41%	0.80	0.67	0 70	0 35
4	Black Hills Corp	45%	0.85	0.75	0 78	0 42
5	Central Vermont Public Service	60%	0 45	0 15	0.24	0 10
6	CH Energy Group	62%	0.75	0.60	0 64	0 43
7	Cinergy Corp	47%	0 80	0 67	0 70	0.39
8	Cleco Corp.	34%	1.00	0 97	0 97	0 43
9	Consolidated Edison	49%	0.60	0.37	0 43	0.22
10	Dominion Resources	40%	0 85	0.75	0 78	0 38
11	DPL, Inc.	26%	0 90	0 82	0 84	0 29
12	DTE Energy Company	41%	0.65	0.45	0.51	0.23
13	Energy East Corp.	39%	0.75	0.60	0 64	0 30
14	Entergy Corporation	53%	0.70	0.52	0 57	0 33
15	FPL Group, Inc	45%	0 65	0 45	0 51	0.25
16	FirstEnergy Corporation	44%	0 75	0.60	0.64	0.33
17	Great Plains Energy, Inc	44%	0.75	0.60	0 64	0 33
18	Hawaiian Electric Industries, Inc.	50%	0.60	0.37	0 43	0.23
19	IDACORP, Inc	46%	0.80	0.67	0 70	0.39
20	MGE Energy, Inc.	57%	0 55	0 30	0 37	0 20
21	NiSource, Inc	42%	0.70	0 52	0 57	0 28
22	NSTAR	40%	0 70	0.52	0 57	0 27
23	OGE Energy Corp	46%	0 65	0.45	0 51	0 26
24	Otter Tail Corporation	54%	0.55	0 30	0 37	0.20
25	Pinnacle West Capital Corp.	49%	0 80	0 67	0 70	0 41
26	PNM Resources	52%	0 80	0.67	0.70	0 42
27	Public Service Enterprise Group, I	27%	0 80	0.67	0 70	0 25
28	Puget Energy, Inc	42%	0.70	0.52	0.57	0.28
29	SCANA Corp.	41%	0.65	0.45	0.51	0.23
30	The Empire District Electric Co	49%	0.65	0.45	0.51	0.27
31	The Southern Company	43%	0 60	0 37	0.43	0 20
32	Wisconsin Energy	40%	0 65	0 45	0.51	0 23
	Mean	45%	**0.72**	**0.55**	**0.59**	**0.30**
	Median	45%	0.70	0.52	0 57	0.29
	Std Deviation	8%	0 11	0.17	0.15	0 08
	Maximum value	62%	1 00	0 97	0.97	0 43
	Minimum value	26%	0 45	0 15	0.24	0.10
	Assumed marginal tax rate	36 5%				

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Fitch 2004 Outlook: U.S. Utilities & Merchant Energy Companies Both Stabilize

15 Dec 2003 1:26 PM (EST)

Fitch Ratings-New York-December 15, 2003: The Rating Outlook for U.S. investor-owned electric utilities and for the competitive energy sector, including generators, diversified energy merchants and energy traders, is Stable, according to an outlook and review of the U.S. utility industry published today by Fitch Ratings.

Behind a definite and sustained stabilization of credit profiles during 2003, however, Fitch has identified volatile natural gas prices, widely varying credit quality within corporate families, event risk from acquisitions and the medium-term refinancing burden of the diversified energy sector as crucial drivers within its overall outlook for the industry over the next five years. Fitch has published several 2004 outlooks concerning the credit outlooks of various industries as well as other fixed-income sectors.

Although the Outlook for the regulated and unregulated sectors is stable in both cases, this masks the divergent paths both segments have taken. While the investor-owned utilities (IOUs) either maintained creditworthiness or are well on their way to recovery, the merchant or competitive energy sector will need much more time (and consistent favorable developments) to recover. In particular, Fitch's outlook report focuses on the $43 billion of speculative-grade debt for refinancing between now and the end of 2009.

Thus, while the diversified energy segment carries mostly Stable Outlooks, the median rating has fallen to the 'B-' category during 2003, implying a one-in-three likelihood of default over five years. The report published today carries a detailed quarterly refinancing schedule for the speculative grade issuers rated by Fitch in the U.S. power & gas sector, sorted by year and by rating category.

The improvement in Outlooks for the regulated sector, 82% of which now carry a Stable Rating Outlook, has reflected decreasing credit contagion from unregulated businesses, stemming in large part from significantly more conservative business strategies, and the resumption of capital market access. There is evidence, however, that event risk for the sector may be rising, as merger & acquisition activity begins to pick up after the very low levels of 2003, led by both traditional utility operators and leveraged acquisition funds.

Rating linkage between parents and affiliates will remain one of the single largest determinants in rating actions, with obvious implications for acquisition structures which increase leverage within the corporate group owning a utility. The report contains an analysis of the root cause behind aggregate Fitch rating actions in each of the past three years, and also highlights a list identifying 29 issuers whose ratings are currently constrained by the credit ratings of their parent company.

The final issue addressed within the outlook report is the exposure of many segments within the U.S. power & gas industry to volatility in natural gas pricing. The report contains a look at Fitch's forward range of gas prices and a discussion of the impact of gas pricing on different power & gas sub-sectors covered by Fitch. The report also contains Outlook Profiles for 21 major power & gas companies, including American Electric Power, The AES Corp., Aquila, Inc., Calpine Corp., Duke Energy Corp., Dynegy Inc., FirstEnergy Corp., Reliant Resources Inc, Williams and Xcel Energy, Inc.

The report 'Outlook 2004: U.S. Power & Gas: Utilities recover; Merchants pause for breath' can be found on Fitch's web site at 'www.fitchratings.com' by linking to the 'Corporate Finance' sector, clicking on 'Global Power' and then 'Special Reports'. Fitch will be maintaining a web page with a full list of 2004 outlook pieces that will be readily available on 'www.fitchratings.com'.

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Dr. Avera's Electric Utility Sample
Historical Dividend Growth
1994-2003

		2003 Dividends	1994 Dividends	10-Yr. Growth Rate
1 Black Hills Corporation		$ 1 200	$ 0.880	3.51%
2 Hawai'ian Electric		$ 1 240	$ 1.170	0.65%
3 MDU Resources Group		$ 0 660	$ 0.470	3 84%
4 PNM Resources	(1)	$ 0 910	$ 0 630	6.32%
5 Pinnacle West Capital		$ 1 730	$ 0 830	8.50%
6 Puget Energy, Inc.		$ 1 000	$ 1 840	-6 55%
7 Sempra Energy	(2)	$ 1 000	$ 1.560	-8.51%
8 Xcel Energy		$ 0.750	$ 1 310	-6 01%
Average				**0.219%**

Notes:
(1) First full year of dividend data 1997
(2) First full year of comparable data 1998

Source Value Line

Dr. Avera's Electric Utility Sample
Value Line Projected Dividend Growth
2004-2007/2009
and 2005-2007/2009

		Value Line 2004 Dividends	Value Line 2005 Dividends	Value Line 2007-2009 Dividends	2004 to 2007-2009 Implied Growth Rate	2005 to 2007-2009 Implied Growth Rate
1	Black Hills Corporation	$ 1 24	$ 1 28	$ 1 40	3 08%	3 03%
2	Hawai'ian Electric	$ 1 24	$ 1 24	$ 1 30	1 19%	1 59%
3	MDU Resources Group	$ 0 70	$ 0 74	$ 0 86	5 28%	5 14%
4	PNM Resources	$ 0 95	$ 0 99	$ 1 11	3 97%	3 89%
5	Pinnacle West Capital	$ 1 83	$ 1 91	$ 2 15	4 11%	4 02%
6	Puget Energy, Inc	$ 1 00	$ 1 04	$ 1 16	3 78%	3 71%
7	Sempra Energy	$ 1 00	$ 1 00	$ 1 00	0 00%	0 00%
8	Xcel Energy	$ 0 77	$ 0 81	$ 0 95	5 39%	5 46%
	Average				**3.350%**	**3.354%**

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HOW IMPROPER RISK ASSESSMENT LEADS TO OVERSTATED REQUIRED RETURNS FOR UTILITY STOCKS

Steven G. Kihm,* CFA

Overview

In discussing investors' required returns on utility stocks, some rate-of-return witnesses focus their testimony on the numerous specific risks affecting the utility under review. Those witnesses often adjust initial estimates of the investors' required return upward to reflect those particular risk factors.

Such testimony assumes that all risks that a company faces affect its investors' required return. That is not the case. It is true that all risks affect the utility's stock price, but only a limited number of them affect the required return. The required return on any company's stock, utilities included, is a function only of its sensitivity to risk factors that affect all stocks (systematic risks); it is not a function of the plethora of risks facing the company in question (firm-specific risks). Firm-specific risk factors affect the other variable that determines stock prices—expectations about a company's future cash flows. This is summarized in the following table.

Firm-specific risk impacts are generally uncorrelated across firms in the economy. Some firm-specific events negatively affect some companies while at the same time other firm-specific events positively affect other companies. The cumulative impact of all the firm-specific risks can therefore be minimized by following the cardinal rule of investing—diversify. In a well-diversified portfolio the countless firm-specific risks affecting individual businesses tend to cancel out. Therefore, the investor who holds a diversified portfolio sees little impact on his wealth from firm-specific risks, and in turn does not consider those risks when determining the required return on any stock.

Why is it so critical to approach required return estimation from the perspective of a diversified investor? Because diversified investors dominate

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TABLE 1
THE IMPACT OF SYSTEMATIC RISKS AND
FIRM-SPECIFIC RISKS ON STOCK PRICE DETERMINANTS

Risk Type	Example	Affects
Systematic	economic recession	required return
Firm-Specific	Increased competition	expected cash flows

Source Author's construct

the trading in financial markets, they therefore determine the market's required return on a stock. Institutional investors are almost universally well-diversified, as are most individual investors, especially when one considers their indirect equity holdings in retirement plans. The smaller group of non-diversified investors is essentially marginalized by the market. They can participate in the market if they wish, but they have to play by the diversified investors' rules.

While diversification is highly effective at reducing risk, it cannot eliminate all risk. Unlike highly localized firm-specific risk impacts, systematic macroeconomic-type risk impacts tend to ripple through the entire stock market. For the investor, there is nowhere to hide from these types of risk factors. Since investors cannot insulate themselves to any great extent from macroeconomic risk factors, their required returns are affected significantly by those risks. The more sensitive a company is to macro-economic risks factors, the higher the required return on the company's stock.

When the inappropriate firm-specific risk factor adjustments are stripped away from the required return determination, we find that investors today demand less than a 10% return on most utility equities. This is supported not only by academic research, but also by research at investment banking and brokerage firms. For example, in August 2002 the investment firm A.G. Edwards estimated that the required return on Consolidated Edison's stock was 8.4%.[1] This level of investor required return is consistent with the well-established concept that

[1] A.G. Edwards, *Consolidated Edison Equity Research Report*, Aug. 5, 2002.

only economy-wide risk factors drive investors' required returns

Risk and Required Return

The finance literature makes it clear that the risk factors that matter in determining the required return on any stock are restricted to those risk factors that affect all stocks. That implies that there are but a few risk factors that are important in this regard. That inference is correct.

Prospective portfolio managers learn in their basic training that the required return for any stock is a function not of the specific risks facing the firm but rather of the firm's sensitivity to changes in macroeconomic factors. Those types of risk factors include the:

- general inflation rate
- national level of industrial production
- spread between yields on low- and high-grade bonds
- term structure of interest rate[2]

While these few factors affect the required return on all stocks, each factor does not necessarily have the same impact on every company. As a result the required return can vary from stock to stock even though the risk factors are the same for all companies.

One does not have to develop exotic financial equations such as arbitrage pricing theory (APT) models to determine the degree to which each macroeconomic factor affects an individual stock.[3] The market has already factored this information into stock prices. A properly applied discounted cash flow (DCF) model for a portfolio of utility stocks will incorporate this risk assessment automatically. The fact that a utility might have substantially more firm-specific risk than other companies in the portfolio has no bearing on whether the required return estimate from the portfolio is appropriate for the utility in question. The particular utility likely has very similar exposure to the key macroeconomic risk factors, and that is what matters. Therefore, the

[2] Charles A. D'Ambrosio, "Portfolio Management Basics," *Managing Investment Portfolios: A Dynamic Process*, in John L Maginn and Charles L. Tuttle, eds , (Warren, Gorham & Lamont, 1990), 2-35.

[3] For a discussion of the application of arbitrage pricing models as they apply to utilities, see Dorothy A. Bower, Richard S. Bower and Dennis E Logue, "Arbitrage Pricing and Utility Stock Returns," *Journal of Finance*, 39(4) (September 1984): 1041-54.

DCF result for a portfolio of utility stocks is likely to represent a reasonable estimate of the investors' required return for all the utilities in the portfolio. That includes a utility that faces very high firm-specific risks as well as a utility facing no firm-specific risks.

This conclusion has interesting implications. The utility investors' required return is essentially unaffected by changes in firm-specific risks, such as those brought about by the introduction of competition in the utility's service territory. On the other hand, the required return is heavily influenced by macroeconomic changes, such as those that might flow from revisions to Federal Reserve Board interest rate policy. Finance witnesses who feel a need to augment their DCF results with additional analysis should therefore focus their testimony on the utility's sensitivity to what is happening in Washington, D.C. rather than what is happening in the utility's service territory.

This is in contrast to the role of utility managers who are responsible for maximizing the firm's cash flow. Because those risks can threaten the utility's cash flows, those individuals need to be aware of the specific risks facing the utility. Rate-of-return witnesses can, however, ignore firm-specific risks precisely because they affect the utility's cash flow rather than the investors' required return.

Investor Responses to Firm-Specific and Systematic Risks

The reason that firm-specific risks do not affect investors' required returns can be explained intuitively as well as theoretically. Whether we realize it or not, most of us act in the way that diversified investors should act. This can be demonstrated with a hypothetical example.

Assume that you have invested in a stock index mutual fund that mimics the price changes of the S&P 500 stock index. If you read a story in *The Wall Street Journal* that the Florida Legislature is considering deregulating its utilities, would you increase your required return on your mutual fund investment? Most likely you would not. Why? You view stocks in a portfolio context, as is proper.

The wealth impact of deregulation on any Florida utility stocks that might be in the mutual fund portfolio

would be miniscule at best. More importantly, the impact would most likely be offset by unrelated events that positively affect other companies in the portfolio. For example, on the day the story on the Florida Legislature appeared, there might be a story indicating that Boeing was likely to be awarded a contract to provide jet airplanes to China. The Florida utility's stock price goes down based on its firm-specific news. Boeing's stock price goes up based on its firm-specific news. The net effect on the mutual fund portfolio value is negligible. This sort of canceling of randomly occurring firm-specific risk impacts has little bearing on your required return on any stock in a well-diversified portfolio.

On the other hand, what if you read that the Federal Reserve Board was considering adopting an aggressive interest rate policy to control inflation? That type of risk factor is much more threatening to your wealth. Sharply rising interest rates tend to take their toll on all stocks. The value of the mutual fund discussed above could decline noticeably under these conditions. The decline would be attributed to a market-wide increase in the required return by investors such as yourself

If interest rates rise, as is being contemplated in this example, the returns on investments that compete with stocks will have increased. If your required return on stocks was 9% when Treasury bonds yielded 4%, you would likely increase the required return on stocks to a level higher than 9% when Treasury bond yields increased noticeably. Shifts in fundamental macroeconomic conditions such as interest rates can, and do, have significant impacts on investors' required returns on all financial instruments, stocks included.

Financial Analysis in Theory and in Practice

The important distinction between diversifiable firm-specific risks and non-diversifiable systematic risks and the manner in which those risks affect stock prices have formed the foundation of investment theory for the past 50 years.[4] Academic finance professionals consulting in practice have recognized that, unfortunately, this foundation

[4] Mark Rubenstein, "Markowitz's Portfolio Selection: A Fifty Year Retrospective," *Journal of Finance*, 57(3) (June 2002): 1041-45

seems to have been left in the classroom by some finance majors. Instead of distinguishing between risks that are relevant to the required return and those that are relevant to the development of expected cash flows, many practitioners lump all risks together and adjust only the required return when any risk factor changes. The entire framework of finance is lost when this occurs, and poor financial decisions result.

Many finance professionals make the common mistake of equating potential bad outcomes with risks that affect the investors' required return. Those are two very different concepts. The widely read *Principles of Corporate Finance* written by Richard Brealey and Stewart Myers notes:

> In everyday usage *risk* simply equals 'bad outcome.' People think of the risks of a project as a list of things that can go wrong. For example, (1) a geologist looking for oil worries about the risk of a dry hole; (2) a pharmaceutical manufacturer worries about the risk that a new drug which cures baldness may not be approved by the Food and Drug Administration; (3) the owner of a hotel in a politically unstable part of the world worries about the political risk of expropriation. Managers often add fudge factors to discount rates [the investors' required return] to offset worries such as these.[5]

Since the impacts of the firm-specific risks discussed in the preceding quote can be diversified away by the investor, adjusting the required return via such a fudge factor is not appropriate. Brealey and Myers continue:

> This sort of adjustment makes us nervous. First, the bad outcomes we cited appear to reflect unique (i.e., diversifiable) risks that would not affect the expected rate of return by investors[6]

None of the risk factors discussed above is linked to macroeconomic activity. Thus, the impact of all of them on the investor can be minimized via portfolio diversification.

It is important to be clear that Brealey and Myers are not saying that firms should ignore the types of firm-specific risk factors discussed above, only that they do not affect the investors' required return. The risk of the oil company drilling a dry hole will affect the ability of the company to generate future

[5] Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance*, (McGraw-Hill, 2003), 235.

earnings and dividends. Brealey and Myers continue their discussion along these lines:

> Second, the need for a discount rate [required return] adjustment usually arises because managers fail to give bad outcomes due weight in cash-flow forecasts.[7]

A manager who has been informed that there is an increased risk that his company will drill a dry hole should revise downward the expected cash flows from the project. He should then discount those estimated cash flows at the same required return that was used before the threat was recognized. This will provide the manager with a reasonable estimate of the value of the project.

A corporate manager who adjusts the investors' required return to reflect all the risks his company faces will tend to overstate that return. Michael Porter of Harvard University has found that such improper financial analysis causes many companies to overstate their investors' required returns by at least a factor of two.[8] This makes capital appear to be much more costly than it actually is and, in turn, leads to less investment than would be optimal for the firm. This not only reduces the potential market value of the firm, but it places the firm at a competitive disadvantage relative to companies that apply the proper techniques.

Risk and Stock Prices

By now, it should be clear to the reader that there is more to stock price determination than the required return. Stock prices are expressed in dollars. The required return is a percentage figure. Something else must enter the stock price equation along with the required return. The other variable is the firm's expected future cash flows. We can use a simple conceptual stock valuation model to demonstrate this point.

Conceptual Stock Price Model

$$price = \frac{annual\ cash\ \ flow}{required\ return} \quad (1)$$

This is the model for pricing or valuing a stream of annual cash flows that is unchanged from year to year (a perpetuity). Other stock price valuation models are more complex variants of this simple model.

[6] Ibid.
[7] Ibid
[8] Michael Porter, "America's Investment Famine," *The Economist* (Jun. 27, 1992), 89.

Diversifiable firm-specific risks affect the cash flows of the firm, which form the numerator of the valuation equation. Non-diversifiable systematic risks affect the required return, which is the denominator of the equation. If we substitute the risk factors for the financial variables in the conceptual stock price model we obtain the following:

Conceptual Stock Price Model

$$price = \frac{f_1 \ (firm-specific \ risks)}{f_2 \ (systematic \ risks)} \quad (2)$$

Interestingly, when viewed through this lens, firm-specific risks appear to be quite threatening to the investor. The equation above reveals that they are, in fact, key determinants of a company's stock price.

Financial research has found that individual stock prices are actually more sensitive to firm-specific, cash-flow related risks than they are to the systematic risks that affect the required return. A recent article in the *Journal of Finance* concluded that firm-specific risk factors produce stock price changes that have twice the variance of the stock price changes caused by the systematic risk factors [9] At first blush, therefore, it would appear that the firm-specific risks are more important, not less important, to the investor than are the systematic risks.

In reaching that conclusion, however, one would be looking through a microscope when binoculars should be used. The entire conclusion of the *Journal of Finance* article must be read to draw the proper inference. The reader following the logic of this paper should see where we are headed. We need to think about these issues in the same manner that a portfolio manager does. His focus is on the value of the portfolio, not the prices of individual securities. Not surprisingly, the *Journal of Finance* article is yet another confirmation of finance theory. The author reports that for large companies, such as those of investor-owned public utilities, the highly volatile, but randomly occurring individual stock price changes caused by firm-specific risk factors tend to neutralize each other in the market. On net, there is no significant effect on the value of diversified portfolios. Thus, since the firm-specific risks do not affect

[9] Tuomo Vuolteenaho, "What Drives Firm-Level Stock Returns?" *Journal of Finance*, 57(1) (February 2002): 233-64.

the portfolio value, they do not affect the portfolio manager's required returns.

Firm-Specific Risks and the DCF Model

We can expand the analysis to consider how firm-specific risks affect particular components of the constant-growth DCF model, which is one of the principal models used to estimate the investors' required return. That model is expressed as:

Constant-Growth Discounted Cash Flow Model

$$\begin{pmatrix} required \\ return \end{pmatrix} = \begin{pmatrix} expected \\ dividend \\ yield \end{pmatrix} + \begin{pmatrix} expected \\ dividend \\ growth \end{pmatrix} \quad (3)$$

What happens when firm-specific risks increase? There are three possible changes. First, the stock price would likely decline because investors would expect that cash flow production will decline. If all else were held constant, the price decline would lead to a higher dividend yield and, therefore, a higher required return. But that conclusion would be premature.

All else will not be held constant if the firm-specific risk is real. There will be offsetting impacts on the other variables. One of two things must occur when a company's cash flow projections decline: either the dividend will be cut or the ability of the company to produce long-term dividend growth will be reduced. A reduction in either of the variables reduces the required return.

We can limit our attention to the two most likely impacts of a firm-specific risk change and ignore the less likely dividend-cut scenario. The dividend yield increase and the expected growth rate decline will have countervailing impacts on the required return. As a result, the required return could mathematically either increase or decrease when firm-specific risks increase. This is summarized in Table 2.

This is where financial analysis can provide critical insight. Both empirical studies and theoretical models suggest that the higher dividend yield will be offset almost entirely by lower

TABLE 2
IMPACT OF INCREASED FIRM-SPECIFIC RISKS
ON INVESTORS' REQUIRED RETURN

DCF Variable	Impact on Required Return
Dividend yield	Increase
Dividend growth	Decrease
Net effect on required return	**?**

Source: Author's construct

growth expectations, leaving the required return essentially unaffected.

Impact of Firm-Specific Risk Increase

$$\left\{\begin{matrix}\underline{higher}\\ dividend\\ yield\end{matrix}\right\} + \left\{\begin{matrix}\underline{lower}\\ expected\\ dividend\end{matrix}\right\} = \left\{\begin{matrix}\underline{no\ change}\\ in\ required\\ return\end{matrix}\right\} \quad (4)$$

If we view only the stock price decline associated with increased firm-specific risk, as some analysts do, then we will draw the incorrect conclusion that the required return is increased—as manifested by a higher dividend yield. Careful analysis shows this conclusion to be in error. The stock price declines in response to the increased risk because the firm's ability to generate cash flow is hampered. But this necessarily means that the firm's ability to produce long-term dividend growth is also compromised. The two impacts tend to offset each other, leaving the required return essentially unchanged relative to what it was before the increase in the firm-specific risk.

Investor Diversification in Practice[10]

It may be helpful to apply the concepts discussed so far to actual stock market data to demonstrate that combining a utility stock with other stocks in a portfolio substantially reduces the risk of investing in the utility without reducing the investors' return.

Wisconsin Energy Corp serves as the utility example. As of October 2002

[10] Finance experts make a distinction between investor diversification and corporate diversification. Investor diversification is highly effective at reducing risk. The fact that it is so effective, however, suggests that corporate diversification is redundant and provides little benefit to a firm's already diversified investors

Wisconsin Energy had a dividend yield of 3.4% and a stock price beta of 0 62.[11] There were many other stocks with characteristics similar to those exhibited by Wisconsin Energy at that time. The following portfolio (see Table 3) of low-risk stocks, which includes Wisconsin Energy, had an average dividend yield and beta factor equal to those of Wisconsin Energy by itself. This portfolio contains 20 stocks from 11 industries. All the stocks pay dividends and have beta factors that are below one. Noticeably missing from the list are stocks of high-tech firms, such as Microsoft, which tend not to pay dividends and which tend to have beta factors in excess of one. An investor who is attracted to utility stocks is more likely to be interested in the types of stocks shown in the portfolio than they would be in high-flying stocks such as Microsoft.

The question being addressed is how an investor's risk exposure changes when he invests in the portfolio instead of investing solely in Wisconsin Energy. The answer is that adopting the portfolio approach substantially reduces the investor's return volatility, which means that risk is substantially reduced. The annual standard deviation of the value of the portfolio is about 35% less than the standard deviation Wisconsin Energy's stock price considered by itself over the same period (see Table 4). The portfolio value is therefore much more stable from day-to-day or year-to-year than is Wisconsin Energy's stock price.

The results presented here are specific to this small portfolio. Even more impressive results have been obtained when diversification has been examined in a more comprehensive fashion. For example, research as far back as 30 years ago revealed that diversification eliminates about 50% of the risk of holding a typical U.S. stock.[12] If one combines international stocks in the portfolio, almost 70% of the risk of

[11] Beta is a measure of the degree to which a price or return on an individual stock is sensitive to changes in the general stock market prices or returns. A beta below 1.0 indicates that the stock is less sensitive than the typical stock to market changes. Conversely, a beta in excess of 1.0 indicates that the stock is more sensitive than the typical stock to market changes.

[12] G A. Whitmore, "Diversification and the Reduction in Dispersion: A Note," *Journal of Financial and Quantitative Analysis*, 5(2) (June 1970): 263-64. Whitmore expresses the reduction in risk in terms of variance reduction. To be consistent with my earlier analysis, I converted the figures to standard deviations. The reductions in risk are even more impressive when viewed in variance terms—75% for U S stocks and 89% for an international stock portfolio.

TABLE 3
PORTFOLIO OF LOW-RISK STOCKS
OCTOBER 2002

Stock	Industry	Dividend Yield	Stock Beta
Abbott Labs	Pharmaceutical	2.3%	0.62
AGL Resources	Natural gas utility	4.9%	0.66
American Water Works	Water utility	2.2%	0.32
Anheuser Busch	Beverages	1.4%	0.56
Coca Cola	Beverages	1.5%	0.67
Consolidated Edison	Electric utility	5.2%	0.49
DTE Corp	Electric utility	4.9%	0.55
Equitable Resources	Natural gas diversified	2.0%	0.73
Exxon-Mobil	Oil and gas integrated	2.7%	0.87
FPL Group	Electric utility	4.4%	0.52
Johnson & Johnson	Medical products	1.4%	0.67
Laclede Gas	Natural gas utility	6.2%	0.64
Merck	Pharmaceutical	3.1%	0.69
New York Times	Newspaper	1.2%	0.83
Northwest Natural Gas	Natural gas utility	4.2%	0.56
PepsiCo	Beverages	1.4%	0.64
Public Storage	Real estate investment	6.1%	0.37
Washington Mutual	Savings bank	3.4%	0.68
Washington Real Estate	Real estate investment	5.8%	0.69
Wisconsin Energy	**Electric utility**	**3.4%**	**0.62**
Portfolio	**Diversified**	**3.4%**	**0.62**

Source: Author's construct

holding an individual stock can be eliminated via diversification. These figures are staggering. When viewed in isolation, stocks appear to be much more risky than they actually are because at least half of the risk associated with holding the stock can be eliminated via diversification.

Returning to our 20-stock portfolio, note that the investor would not have to accept a lower return to obtain the lower risk provided by the portfolio. In this example the annual total return on the portfolio is identical to the annual return on Wisconsin Energy's stock. These results are also shown in Table 4.

This is why financial experts are so unequivocal about recommending that investors diversify. The lower risk that results from diversification does not come at the expense of the investor's return.

Note also that the reduction in risk gained by investing in the portfolio was achieved by combining Wisconsin Energy stock with stocks that were generally more volatile, not less volatile, than Wisconsin Energy. Seventeen of the 19 other stocks added to create the portfolio have stock price standard deviations that are equal to or greater than Wisconsin Energy's stock price standard deviation. Nevertheless, because firm-specific impacts on stock prices are not correlated across the companies in the portfolio, price increases for some stocks are offset by simultaneous price decreases for other stocks. As a result of these offsetting impacts, the standard deviation of the portfolio value is substantially below the standard deviation of stock prices for any of the individual companies in the portfolio.

With respect to risk, when an investor diversifies the total is less than the sum of the parts. This is a welcome outcome for the investor. The key point here is that diversification makes stocks much less risky for the investor than they would appear to be when viewed in isolation. Market-determined required returns reflect that fact.

TABLE 4
RISK AND RETURN
PORTFOLIO OF LOW-RISK STOCKS
1997-2002

Stock	Annual Standard Deviation (risk)	Annual Total Return
Abbott Labs	31%	8%
AGL Resources	21%	6%
American Water Works	26%	18%
Anheuser Busch	26%	23%
Coca Cola	33%	-1%
Consolidated Edison	25%	9%
DTE Corp	24%	11%
Equitable Resources	28%	20%
Exxon-Mobil	26%	5%
FPL Group	24%	4%
Johnson & Johnson	29%	15%
Laclede Gas	22%	3%
Merck	32%	1%
New York Times	31%	10%
Northwest Natural Gas	25%	8%
PepsiCo	30%	4%
Public Storage	23%	6%
Washington Mutual	41%	3%
Washington Real Estate	20%	15%
Wisconsin Energy	**22%**	**9%**
Portfolio	**14%**	**9%**

Source: Author's construct

The Cost of Diversification

Diversification today can be achieved at very low cost. Mutual funds are excellent diversification vehicles for small investors. For example the management fee for a typical S&P 500 index fund is less than one-half of 1%. Paying one-half of 1% to obtain the diversification benefits associated with 500 stocks is a very efficient way to invest. Most individual investors would have a difficult time finding a better deal than an index fund, which not only tends to exhibit low volatility but produces returns that are higher than those of most actively managed portfolios.

Investors who choose to manage their own investments may incur somewhat higher transaction costs than those associated with an index fund. But those investors do so of their own volition, since more cost-effective diversification options are available.

Diversification is inexpensive for institutional investors, as well. Investment firms compete aggressively to provide brokerage services for institutional clients. The highly competitive environment in which institutional brokers operate is manifested by the very low fees institutions pay when they trade stocks.

Diversified and Non-Diversified Investors

When faced with the overwhelming evidence that diversifiable firm-specific risks do not affect the required returns of diversified investors, some finance witnesses attempt to show that some investors who hold the stock of the particular utility under review are not well-diversified. For example, some witnesses present results of surveys that show that many investors own three or fewer individual stocks. They then argue that the required return on the utility stock must reflect both firm-specific and systematic risks. There are three significant errors of logic in this argument: (1) knowing who holds the stock tells us little about who is trading the stock in the market and, therefore, little about the market's required return on the stock; (2) knowing the number of individual stocks that an investor owns provides little information about diversification of the investor's complete financial portfolio; (3) knowing that an

investor holds a non-diversified portfolio does not mean that the investor could not diversify if he or she chose to do so.

If we think this through for a moment we can see that even if many non-diversified investors hold a particular utility's stock, the market's required return will be set by the diversified investors. There is only one market-determined required return embedded in the stock price for a given company. Put another way, the market does not develop one required return for diversified investors and a different required return for non-diversified investors. The single required return on a given stock is set by buyers and sellers in the financial markets.

Who are the buyers and sellers? Examining who holds a stock (individual investors typically hold a little more than half of most utility's securities) will not tell you who is trading the stock. Individual investors tend to be more of the buy-and-hold variety. Institutions dominate the trading in stocks. Moreover, almost all institutional investors are required by law or charter to be well-diversified.[13] It is these well-diversified institutional investors who set the price for the stock; therefore, it is the well-diversified investors who determine the market's required return on the stock.

In highly competitive financial markets, any institutional investors who try to demand a return that compensates them for firm-specific risks will find no stocks to buy. Diversified investors do not demand compensation for firm-specific risks; therefore, the market-determined required return will not reflect those risks. This means that diversified investors will pay more for a given stock than will the investor demanding the higher return. Any investor, either diversified or not, who wants to participate in the market will have to accept stock prices set by diversified investors. This applies to individuals as well as institutions.

Does this mean that individual investors are not being compensated for

[13] Jerome B. Cohen, Edward D. Zinbarg, and Arthur Zeikel, *Investment Analysis and Portfolio Management* (Irwin, 1987), 175

the risks they take when they hold individual stocks? No. Diversified investors determine the market's required return on individual stocks based only on the sensitivity of each stock to systematic risk factors, because those are the only risks that have a noticeable effect on the value of their portfolios. Moreover, most individual investors, even those who own only one or two individual stocks, are actually well-diversified. Survey results that report only the number of individual stocks the typical investor holds but that do not also reveal the value of those investments relative to the typical total financial portfolio (including indirect equity holdings) tell us little about whether the investor is well-diversified. Many individuals who own a few stocks also hold well-diversified mutual funds in their portfolios. More importantly, however, most individuals have relatively large amounts of money in indirect equity investments. For example, most individual investors are covered by well-diversified retirement plans

Even if investors are not diversified, it is likely that they could be. There are very few, if any, investors who could not diversify if they wanted to do so, as is explained in the modern corporate finance texts.

> For investing amounts smaller than $25,000 and when wanting the responsibility of managing their own portfolio, investors can invest in mutual funds to approximate the market portfolio. Currently, there are index funds, such as those based on the Standard & Poor's 500 Index. In fact, an important reason for the existence of mutual funds is to provide the opportunity to all investors to diversify inexpensively.[14]

If the few remaining non-diversified investors find the market-determined required returns to be too low, they can diversify to reduce their exposure to the utility's firm-specific risks or they can sell the stock. The degree of diversification is a choice made by the investor, not a condition imposed from the outside. The regulator clearly has no obligation to compensate a non-diversified investor for risks that could be easily avoided.

[14] Donald R. Emery and John D Finnerty, *Principles of Finance With Corporate Applications* (West Publishing Company, 1991), 176 [Emphasis added.]

Required Return Estimation in Regulatory Proceedings

Rather than the approach suggested by finance principles being used, in regulatory proceedings we often see incorrect *ad hoc* approaches to required return estimation. A finance witnesses' discounted cash flow (DCF) analysis might suggest that the required return on the typical utility stock today is 10%. Then the witness might suggest that investors require a higher return on the utility in question because it faces higher-than-average competition risk, its exposure to risks related to its nuclear plants is relatively high, its fuel mix is not as diversified as that of other utilities, its largest customer is threatening to relocate to another state, and its regulatory climate is not highly regarded by the investment community.

As was discussed above, these items represent firm-specific risks. They affect the cash flow forecasts for the utility–not investors' required return. The required return on the utility stock in this example is 10%, just as the DCF model suggests. Table 5 presents the required return determination from the perspective of the finance witness who treats all risks as though they affect the required return (the *ad hoc* approach), and from the perspective of the witness who applies financial principles. *Ad hoc* required return adjustments of the magnitude shown above are common in regulatory hearings. This is baffling in that such adjustments have no financial basis. The witness who employs them is literally making things up as he goes along rather than applying well-established financial concepts.

In this example, utility investors are fully compensated for the risks they take if the 10% return is authorized by the regulator. Authorizing returns in excess of that level to account for firm-specific risks serves only to institutionalize bad financial practice. The utility consumer bears the brunt of that mistake.

Proper Estimation of Investors' Required Returns

Since firm-specific risks are not relevant to the required return, regulators can ignore any adjustment suggested for those items when setting a utility's authorized return. In most

TABLE 5
HYPOTHETICAL REQUIRED RETURN ESTIMATES
TWO APPROACHES

Item	Ad Hoc Approach	Financial Principles Approach
Portfolio DCF estimate	10.00%	10.00%
Competition risk adjustment	0.50%	—
Nuclear risk adjustment	0.25%	—
Fuel diversity risk adjustment	0.50%	—
Customer loss risk adjustment	1.50%	—
Regulatory climate risk adjustment	0.25%	—
Required return estimate	**13.00%**	**10.00%**

Source: Author's construct

cases a properly derived DCF-based required return estimate for a portfolio of utility companies will provide a reasonable estimate of the investors' required return on the utility's stock. Since only systematic risks are considered when diversified investors set stock prices, DCF-based required return estimates will not include the impacts of firm-specific risk factors. Neither should the regulator.

DCF-based required return estimates for utility stocks today typically lie below 10%. For example, in October 2002 the dividend yield on the Dow Jones Utility Index was 6%. Over the past 50 years or so utility dividends per share have grown at about 2 to 3% per year. The constant-growth DCF model would suggest in that case that the required return on a utility stock today is about 8 to 9%.

Some rate-of-return experts would likely suggest that the growth rate used in the preceding analysis is too low. They might argue that stocks analysts' forecasts of earnings growth for the next three to five years, which are sometimes used as a proxy for long-term dividend growth, are much higher than 2 to 3%. There are several problems with this argument.

No one, including the stock analysts, is suggesting that a utility can necessarily sustain indefinitely growth rates that the analysts project to occur

only over the next three to five years. While dividend growth rates of varying degrees could occur in the near term, there is no reason to believe that the long-term sustainable growth rate will vary substantially from the historic rate of 2 to 3%.

Financial research has made it clear that no company, especially a utility, can sustain a growth rate over the long run that exceeds the growth rate of the economy.[15] Since 1959, the long-term sustainable real rate of growth in the economy has been about 3.5%.[16] If the long-term inflation rate is expected to be about 2.5%, the maximum long-term sustainable nominal growth rate for any company today is about 6.0%. Since utilities are among the slowest growing firms in the economy, a utility today would be expected to have a long-term nominal sustainable growth rate that is significantly lower than 6%. Assumed long-term growth rates for utilities today that are noticeably in excess of 3% should raise questions of reasonableness in the mind of well-trained rate-of-return experts.

If the growth prospects for a company truly are relatively high in the near term, the analyst should use a multi-stage DCF model to estimate the required return. The higher growth rate can be used for the initial period (e.g., five years), but the long-term growth rate must be a sustainable one.

The other problem with using analyst forecasts as the long-term growth rate in a DCF model is that such forecasts are biased to the upside. The evidence on this issue is overwhelming.[17] The forecast bias persists year after year in large part due to incentive structures in place at many Wall Street firms that tend to reward more optimistic projections and to discourage the incorporation of potentially negative views in analysts' forecasts.[18]

To put an 8 to 9% required return on a utility stock in perspective, we can

[15] Robert D. Arnott and Peter L. Bernstein, "What Risk Premium is Normal?" *Financial Analysts Journal*, 58 (2) (March/April 2002): 64-85.
[16] Source: Council of Economic Advisors, *Economic Report of the President*, 2002.

[17] See for example, Vijay Kumar Chopra, "Why So Much Error in Analysts' Earnings Forecasts?" *Financial Analysts Journal*, 54(6) (November/December 1998): 35-42.
[18] See Masakao N. Darrough and Thomas Russell, "A Positive Model of Earnings Forecasts: Top Down Versus Bottom Up," *Journal of Business*, 75(1) (January 2002): 127-52.

look to the research of Wall Street investment advisors. Institutional investment advisors today suggest that the required return on equity today for a typical stock is at most 500 basis points above the long-term Treasury bond yield, and possibly much lower.[19] The current 10-year Treasury bond yield of 4% suggests that the required return on a typical stock today is therefore no more than 9%. The required return on a utility stock would be somewhat lower.

These lower equity risk premiums are in contrast to historic returns on stocks that were about 700 basis points over the T-bond yield for much of the 20th century. The fact that the historic risk premium estimates lead to substantially overstated required return estimates is now widely held within both the academic and institutional investment communities.[20] Roger Ibbotson, the founder of Ibbotson Associates, a firm that publishes historic risk premiums figures, suggests that those historic returns produce required returns estimates that are too high given today's equity risk premiums.[21] In addition, investment research by Professor Jeremy Siegel has shown that over the very long run (200 years instead of the typically used 75 years) the stable and more statistically reliable long-term historic risk premium is much less than that observed in more recent decades.[22]

The required returns on common stocks suggested by the mainstream finance community today appear low only if one expects to receive compensation for the firm-specific risks that affect individual stock prices. But what if we ignore the firm-specific risks? If the Treasury bond yield were 4%, it would be difficult to argue convincingly that a 9% return is unreasonable if the only risks that truly threaten investor returns are macroeconomic factors such as potential changes in interest rates.

When viewed in isolation, stocks appear to be at least twice as risky as they actually are to the diversified

[19] Arnott and Bernstein, "What Risk Premium is Normal?"

[20] See Eugene F. Fama and Kenneth R. French, "The Equity Premium," *Journal of Finance*, 57(2) (April 2002): 637-59, and Deutsche Asset Management, *What Can We Expect for Asset Returns in the Long Term?* 2001.

[21] See *Proceedings: AIMR's Equity Risk Premium Forum*, Nov. 8, 2001, 103. The proceedings are available on-line at the Association for Investment Management and Research's publications website (www.aimrpubs.org).

[22] Jeremy J. Siegel, *Stocks for the Long Run*, (McGraw-Hill, 2002).

investors who dominate markets and ignore firm-specific risks when determining required returns. Financial academics know that. So do Wall Street investment advisors. When viewed from the proper risk perspective, the conclusions of financial academics and Wall Street investment advisors that required returns on stocks today are below 10% appear to be quite reasonable.

An Investment Advisor Analyzes a Utility Stock

The 8 to 9% required return level suggested by the DCF model discussed above is also consistent with utility required return estimates found in specific stock analyst research reports. For example, in an August 2002 research release A.G. Edwards suggested that the required return on Consolidated Edison's stock was 8.4%.[23] A.G. Edwards reported that this estimate was derived from a risk premium model (its required return model for utilities adds 300 basis points—or 3%—to the 30-year T-bond yield).

The risk-premium-based required return estimate and forecasted cash flows were then entered into a DCF stock price model to estimate the intrinsic value of Consolidated Edison's stock. The analyst found that Consolidated Edison's stock was worth $42 per share at the time. The analyst concluded that Consolidated Edison's stock was fairly valued because it traded at almost exactly the same price as his valuation model suggested it should ($41.40 per share)

The same A.G. Edwards research report also discussed numerous firm-specific risk factors affecting Consolidated Edison. Those risks include the potential for:

- lower earnings in the near term
- adverse regulatory decisions
- non-recovery of higher-than-expected purchase power costs
- unsuccessful acquisitions
- below average customer growth
- poor local economic conditions related to the September 11 attacks
- increased competition in the service territory

[23] A.G. Edwards, *Consolidated Edison Equity Research Report*, Aug. 5, 2002, 6

- deterioration in the quality of earnings related to pension costs adverse decisions in pending lawsuits

Nonetheless, A.G. Edwards did not adjust the 8.4% required return estimate to reflect these risk factors. Instead, it discussed the firm-specific risk factors in the context of their potential impact on Consolidated Edison's ability to generate future cash flows. This is proper risk-return analysis.

If the risks do not affect the required return, why does A. G. Edwards spend so much time analyzing those firm-specific risks? We have to remember that even though firm-specific risks do not affect the required return, they are still quite important to investors. If the investor understands all the risks Consolidated Edison faces, he can get a better handle on its ability to generate cash flow in the future. Combining the outlook on cash flows with the 8.4% required return allows the investor to develop his own estimate of Consolidated Edison's intrinsic value. If that value appears to be higher than the current stock price, the investor may decide to add this stock to his portfolio.

Conclusion

Risk and return are important issues in regulatory proceedings. Understanding how risks affect stock prices leads to better estimates of the market's required return on utility stocks. Risks that are specific to the utility affect expectations about future utility cash flows, but they have little bearing on the investors' required return. Regulators should therefore ignore testimony suggesting that firm-specific risks influence the required return. Once the inappropriate firm-specific risk adjustments are eliminated, regulators will likely find that the required returns on most utilities stocks today are below 10%.

Witness Qualifications Statement

NAME JOHN S THORNTON, JR

ADDRESS 7929 E Joshua Tree Lane, Scottsdale AZ 85250

EDUCATION

Master of Science Degree from the University of London, having completed the graduate program in economics at The London School of Economics and Political Science (1986)

Graduate Diploma in Economics from The London School of Economics (1985)

Bachelor of Arts degree, major in economics, from Willamette University (1984).

Certified Rate of Return Analyst, member of the Society of Utility and Regulatory Financial Analysts

1998 passed level I of the CFA
1995 PaineWebber Seminar on Corporate Finance for the Utility Industry
1990 MIT/Harvard Public Disputes Resolution Program seminar.
1990 National Association of Regulatory Utility Commissioners (NARUC) Advanced Regulatory Studies Program.
1988 NARUC Annual Regulatory Studies Program

EXPERIENCE

Chief, Financial & Regulatory Analysis Section, Utilities Division, Arizona Corporation Commission, 2001 to January 2004

•Testified in the following dockets
•W-01656A-98-0577 & WS-02334A-98-0577—Sun City Water Co and Sun City West Utilities Co 's request for approval of the Central Arizona Project water utilization plan
•E-01345A-02-0707—Arizona Public Service Co 's application for authority to incur $500,000,000 of debt and to acquire a financial interest in an affiliate
•E-01345A-02-0840—Arizona Public Service Co 's application for authority to loan $125,000,000 of debt to an affiliate.
•E-01345A-02-0403—Arizona Public Service Co 's application for approval of adjustment mechanisms
•E-01032-00-0751, G-01032A-02-0598, E-01933A-02-0914, E-1032C-02-0914, G-01032A-02-0914—Consolidated dockets of UniSource, Citizens Communications Arizona Gas Division (AGD), & Citizens Communications Arizona Electric Division (AED); general rate case for the AGD, PPFAC adjustment for AED, and sale of AGD and AED to UniSource
•W-01445A-02-0619—Arizona Water Company's application for rates and charges for eight systems. Testimony on implementing lifeline rates and marginal cost pricing into rate design, resulting in inverted block rates.

Witness Qualifications Statement (continued)

•W-03512A-03-0279—Pine Water Company's general rate case Testified on financing request to convert inter-company note payable to debt and equity and rate of return

Senior Analyst with the Public Utility Commission of Oregon, 1988-2001
•Testified or provided rate of return analyses in the following dockets
•UE 102—PGE disaggregation/general rate case (chief rate of return witness)
•UE 94—PacifiCorp general rate case (chief rate of return witness)
•UE 93 (UM 592, UM 694)—Portland General Electric Co. excess power cost/Coyote/BPA filing
•UE 92—Idaho Power general rate case.
•UE 88—Portland General Electric Co general rate case (chief rate of return witness)
•UE 85/UM 529—Portland General Electric Co Earnings test for Trojan Shutdown Cost Adjustment Account
•UE 84—Idaho Power Co deferred account earnings benchmark.
•UE 82/UM 445—Trojan Outage Cost Adjustment Account earnings test benchmark
•UE79—Portland General Electric Co. general rate case (chief rate of return witness).
•UG 104/UG 105/UG 106—LDC deferred account earnings test benchmarks
•UG88—Cascade Natural Gas Co general rate case (chief rate of return witness)
•UG81—Northwest Natural Gas Co general rate case (chief rate of return witness)
•UT 125—US WEST Communications, Inc general rate case (chief rate of return witness)
•UT 113—GTE Northwest general rate case (chief rate of return witness)
•UT101—United Telephone Co of the Northwest general rate case (chief rate of return witness).
•UT85—US WEST general rate case (capital structure and debt cost witness)
•RP95-409—Northwest Pipeline general rate case (FERC)
•RP93-5—Northwest Pipeline general rate case (FERC)

Responsibilities also included the following:
•Analyses and recommendations in over fifty financing dockets
•UM 903— Northwest Natural, cost of capital analysis for purchased gas adjustment mechanism.
•UM 21—Cost of capital analysis for avoided cost calculations
•UM 351—Cost of capital analysis for long-run incremental-cost studies.
•UM 573—Analysis of purchased power on the utility's cost of capital
•UM 773—Cost of capital analysis for long-run incremental-cost studies
•UM 814—Enron's application to acquire Portland General Electric Co
•UM 918—Scottish Power plc's application to acquire PacifiCorp
•UM 967—Sierra Pacific Resource's application to acquire Portland General Electric Co

Witness Qualifications Statement (continued)

Speaker—US Agency for International Development's Conference on Private Sector Participation in the Colombian Power Sector

Presented beta adjustment and distribution risk discount testimony on behalf of the Division of Ratepayer Advocates of the California Public Utility Commission, Application Nos 98-05-019, 021, & 024

Sierra Pacific Power Co compliance filing docket no 99-4001 and Nevada Power Co compliance filing no 99-4005 rate of return witness for intervenors Mirage Resorts, Inc , Park Place Entertainment Corp , and the Mandalay Group

Corporate finance witness for the Industrial Customers of Northwest Utilities, Docket No UE 010395, Avista Utilities

Docket Nos 01-10001 and 01-10002 re application of Nevada Power Co for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto Rate of return witness for intervenor MGM-Mirage

Docket Nos 03-10001 and 03-10002 re· application of Nevada Power Co for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto Rate of return witness for intervenor MGM-Mirage

Docket No UM 1121 re application of Oregon Electric Utility Company to acquire Portland General Electric Co from Enron Merger & acquisition analysis on behalf of the Industrial Customers of Northwest Utilities

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY

DIRECT TESTIMONY
OF
JOHN S. THORNTON, JR.

ON BEHALF
OF
RESIDENTIAL UTILITY CONSUMER OFFICE

SAMPLE TESTIMONY
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2004

EXECUTIVE SUMMARY
PREFILED DIRECT TESTIMONY
OF
JOHN S. THORNTON, JR.

DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY

Mr. Thornton also addresses Ernst & Young's OPERA method to estimate the cost of equity presented by John F. Devlin. The OPERA method ostensibly relies on the Sharpe Ratio, a ratio developed and used to compare performances of different mutual funds over a specific investment period. The Sharpe Ratio is not used to estimate the cost of equity to a company. Mr. Thornton finds that Mr. Devlin has misapplied the Sharpe Ratio and miscalculated it. Mr. Devlin then increased the results from his Sharpe Ratio analysis based on his proprietary regression analysis and a dispersion of allowed ROEs. Mr. Thornton also finds that this increase and the regression behind it are inappropriate and inconsistent with corporate finance theory.

Prepared Direct Testimony of John S. Thornton, Jr.
DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY
2004

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Examination of Mr. Devlin's Cost of Equity OPERA Analysis

Q. WHAT CORPORATE FINANCE THEORY DOES DEVLIN USE TO ESTIMATE APS' COST OF EQUITY?

A. Mr. Devlin does not appropriately use any corporate finance theory to estimate APS' cost of equity. He uses a proprietary Ernst & Young Operating Approach (OPERA) methodology for electric utilities. The method appears designed to increase allowed ROEs. In fact, his analysis violates corporate finance theory.

Q. PLEASE DESCRIBE THE OPERA.

A. The OPERA is a two-step process. In the first step, Mr. Devlin estimated the cost of equity to the electric utility industry. In the second step, he adjusted it upward based on his assessment of APS' risk.

Mr. Devlin's "Sharpe Ratio"

Q. IS THE OPERA'S FIRST STEP APPROPRIATE?

A. No. The OPERA's first step is not appropriate. Mr. Devlin claims to use the Sharpe Ratio to estimate the electric industry's cost of equity. Not only can one not use the Sharpe Ratio to estimate the cost of equity, but Mr. Devlin miscalculated every input to the Ratio.

Q. WHAT IS THE SHARPE RATIO USED FOR IN FINANCE?

A. The Sharpe Ratio is used to rank mutual funds. Dr. Sharpe describes the Sharpe Ratio in his article *Morningstar's Performance Measures: Sharpe Ratios*, pages 4 to 5,

> Consider an investor who plans to put all her money in either fund X or fund Y...Note that in this example it is assumed that only one risky investment is to be undertaken. The reason that the Excess Return Sharpe Ratio is, in principle, designed to deal with this situation is not difficult to see--the measure of risk is the total risk of the fund in question. But in a multi-fund portfolio, both the total risk of a fund and its correlation with movements in other funds is relevant. Since the Excess Return Sharpe Ratio deals only with the former, it is best suited to investors who wish to choose only one risky mutual fund...Retrospectively, an historic Excess Return Sharpe Ratio can provide and answer for an investor with the question:
>
> *If I had invested in only one fund and engaged in borrowing or lending, as desired, which would have been the single best fund?*

Therefore, the Sharpe Ratio is a tool to decide between two mutually exclusive portfolios.

Q. IS THE SHARPE RATIO USED IN FINANCE TO ESTIMATE THE COST OF EQUITY TO A FIRM IN ADDITION TO A PORTFOLIO COMPARISON TOOL?

A. No. The Sharpe Ratio is strictly used as an *ordinal* measure to *compare* or *rank* mutual funds over a specific time period. In other words, the Ratio is a measure to compare fund X's performance with portfolio Y's performance over a period such as the past ten years. The Ratio is not used to compare the performance of a single fund over two different time periods. Nor is the Ratio used as a cardinal measure to estimate the cost of equity to a firm at a point in time. The Sharpe Ratio is calculated using the following equation:

$$\text{Sharpe Ratio} = \frac{\text{Average portfolio return minus the risk-free rate}}{\text{Standard deviation of the portfolio returns}}$$

The fund returns, risk-free rate, and standard deviation of the mutual fund are measured for an interval of time (such as a year) over a period of intervals (such as ten years). Since a mutual fund is a portfolio of securities, I'll use the terms interchangeably.

The Sharpe Ratio is calculated for multiple portfolios and their Sharpe Ratios are compared to determine which portfolio was better over that time period. The portfolio with the highest Sharpe Ratio is the best portfolio, relatively speaking. Risk in the Sharpe Ratio is measured by standard deviation, a statistical measure for the dispersion of data; a larger standard deviation means a wider dispersion of data.

Let me give you an example of how a Sharpe Ratio is calculated. Let's say you were presented with the data in the table below and were trying to determine which portfolio was better. While Portfolio B had a higher return you are insightful enough to inquire whether its higher reward was offset with higher risk. To compare Portfolio A and Portfolio B you might use the Sharpe Ratio:

Sharpe Ratio Example		
Year	Portfolio A	Portfolio B
1994	1.31%	3.11%
1995	37.43%	34.46%
1996	23.07%	17.62%
1997	33.36%	22 78%
1998	28.58%	-7 31%
1999	21.04%	29.79%
2000	-9.11%	-3.59%
2001	-11.88%	22.77%
2002	-22.10%	-13.28%
2003	28.70%	60.70%
Average portfolio return·	13.04%	16.71%
Standard deviation:	21.46%	22.53%
10-yr. risk-free rate in Jan '94	5.75%	5.75%
Sharpe Ratio	0.34	0.49

The Sharpe Ratio for Portfolio A is .34 ([13.04% - 5.75%]/21.46%) and the Sharpe Ratio for Portfolio B is .49 ([16.71% - 5.75%]/22.53%). Therefore, you conclude that Portfolio B indeed had a better reward-to-risk ratio than Portfolio A because it has a higher Sharpe Ratio. This comparison assumes that the two portfolios are similar (but that you can only invest in one or the other) and that they relate similarly to all other available securities (have similar correlations with other holdings).

Q. WHAT DOES WILLIAM SHARPE HAVE TO SAY ABOUT USING STANDARD DEVIATION AS THE RELEVANT MEASURE OF RISK FOR SECURITIES SUCH AS ELECTRIC UTILITY STOCKS?

A. William Sharpe writes in his textbook *Investments* that,

> "Accordingly, each investor will note that the relevant measure of risk for a security is its covariance with the market portfolio, σ_{iM}."

In other words, a security's standard deviation is not the relevant measure of risk. The relevant measure is a security's covariance with the market portfolio. Mr.

Devlin relied on standard deviation, in contradiction to Dr. Sharpe's view. The notion of covariance risk is the key insight that led to two of the 1990 Nobel Prizes in Economics. I include the quoted passage from Dr. Sharpe's textbook as pages 48-55 of Exhibit JST–1.

Mr. Devlin's own working papers include a reprinted article by Dr. Sharpe discussing the Sharpe Ratio. On page 13 of the article Dr. Sharpe writes,

> "The Sharpe Ratio is designed to measure the expected return per unit of risk for a zero investment strategy. The difference between the returns on two investment assets represents the results of such a strategy. The Sharpe Ratio does not cover cases in which only one investment return is involved."

In this proceeding we are interested in the return on one investment: the required return on a sample of electric utilities. On page 8 of the article, Dr. Sharpe writes,

> "Asset risk, however, will depend on both the relative risk (k) and the correlation of the strategy with the other investments (rhoID). In general, the Sharpe Ratio, which does not take that correlation into account, will not by itself provide sufficient information to determine a set of decisions that will produce an optimal combination of asset risk and return, given an investor's tolerance of risk."

In other words, covariance with other investments matters. Mr. Devlin has in no way accounted for beta risk or covariance with other assets in his analysis. I include the full article from Mr. Devlin's working papers as pages 56-71 of Exhibit JST–1.

Q. EVEN IF THE SHARPE RATIO WERE APPROPRIATE FOR MR. DEVLIN'S PURPOSES, DID HE ESTIMATE THE INPUTS TO THE SHARPE RATIO CORRECTLY?

A. No. Mr. Devlin did not calculate any of the inputs correctly. I will take the inputs in turn and discuss their calculation problems.

The Ratio's Numerator

Q. PLEASE DESCRIBE HOW THE SHARPE RATIO'S NUMERATOR SHOULD BE CALCULATED.

A. The numerator is supposed to be the difference between the average (annual) market return on a fund over some period minus the (annual) return on the risk-free rate that could have been purchased at the beginning of that period. (The differential is typically measured in annual intervals as did Dr. Sharpe in his original article.) For example, you could calculate the average annual return on a Standard & Poor's 500 fund over a ten-year period (say, 13.04 percent from the example above) and subtract the yield on a ten-year U.S. Treasury security that prevailed at beginning of the five years (say 5.75 percent from the example above). That 7.29 percentage point difference is the numerator.

Q. HOW DID MR. DEVLIN CALCULATE THE NUMERATOR AND HOW IS HIS CALCULATION INAPPROPRIATE?

A. Mr. Devlin averaged the allowed ROEs across utilities *in a given year* and subtracted a risk-free rate for that year. The first and most obvious problem is that the Sharpe Ratio is calculated on market returns (such as from data you would observe in *The Wall Street Journal*) but Mr. Devlin used allowed ROEs. Allowed ROEs are not appropriate in the Sharpe Ratio.

Second, Mr. Devlin did not calculate the average annual market return over a number of years. He miscalculated the numerator because he inappropriately calculated the difference between the average allowed ROEs and a risk-free rate *in a given year* rather than calculate the average market return *over a number of years* and then subtract the risk-free rate prevailing at the beginning of the period. His calculation has no meaning because the Sharpe Ratio is intended to measure the reward-to-risk ratio over a period of time (such as ten years), which is then compared to other portfolios' Sharpe Ratios. Mr. Devlin's mistaken calculation method, in the context of my example above, would result in him calculating the average return across all the stocks' returns in Portfolio A in any given year minus a risk-free rate in that year rather than the average return of Portfolio A over time as should be done.

Third, Mr. Devlin used long-term rates as the risk-free rate. If the average market return for a portfolio were taken over a ten-year period, then ten years is implicitly assumed as the investment horizon and a ten-year risk-free rate would be used. Mr. Devlin's calculation has no meaning because it does not calculate market returns over a period of time, but even if it did have meaning then a long-term risk-free rate would clearly be inappropriate because a long-term rate is associated with a long-term investment horizon.

The Ratio's Denominator

Q. PLEASE DESCRIBE HOW THE SHARPE RATIO'S DENOMINATOR SHOULD BE CALCULATED.

A. The Sharpe Ratio's denominator should be calculated as the standard deviation of a fund's annual returns over a period of time such as ten years, continuing with the example above. The standard deviation of Portfolio A's annual returns over the ten years is 21.46 percent and the standard deviation of Portfolio B's annual returns over the ten years is 22.53 percent.

Q. HOW DID MR. DEVLIN CALCULATE THE DENOMINATOR AND HOW IS HIS CALCULATION INAPPROPRIATE?

A. Mr. Devlin calculated the denominator as the standard deviation of returns on rate base (ROR) across utilities in a given year. The most obvious problem is that he has calculated a standard deviation based on ROR data that are totally different from the allowed ROE data in the numerator. One cannot calculate the Sharpe Ratio using one data series in the numerator and a totally different data series for the denominator.

The more subtle, but critical, flaw in Mr. Devlin's denominator is that he has miscalculated the standard deviation. Mr. Devlin calculated his standard deviation as the standard deviation, or dispersion, of RORs across utilities *in any given year*. However, the Sharpe Ratio requires the standard deviation of a portfolio's annual returns *over a length of time*, such as ten years. In statistical terms, he calculated the cross sectional standard deviation of RORs across the electric industry; however, the Sharpe Ratio requires the time series standard deviation of portfolio returns over time. The two are completely different in spirit and calculation.

Mr. Devlin's mistaken calculation method, in the context of my example above, would result in him calculating the standard deviation of returns across all the stocks' returns in Portfolio A in any given year minus a risk-free rate in that year rather than the average return of Portfolio A over time.

Mr. Devlin's Application of the Sharpe Ratio

Q. YOU HAVE EXPLAINED HOW THE SHARPE RATIO IS NOT USED TO ESTIMATE THE COST OF EQUITY AND HOW MR. DEVLIN MISCALCULATED THE SHARPE RATIO. CAN YOU EXPLAIN HOW HE APPLIED IT IN A MANNER THAT WOULD BIAS HIS ESTIMATES UPWARD?

A. First, Mr. Devlin has calculated a "Sharpe Ratio" for only one portfolio of stocks: a portfolio of electric utilities. A Sharpe Ratio for Portfolio A is meaningless by itself without comparison to the Sharpe Ratio from another portfolio for the same time period. Mr. Devlin has not calculated a Sharpe Ratio for any other portfolio of stocks to compare to his calculation.

Second, I have already discussed how the Sharpe Ratio cannot be used to calculate the cost of equity for a utility in this context. However, I do want to take the opportunity to express concern that Mr. Devlin inconsistently picked and chose amongst various averages he calculated to target a high cost of equity estimate. The most recent of his Ratio calculations is 1.96 yet he chose 2.5 to "return the industry's reward-to-risk ratio almost to the levels observed from 1991 to 1998." (*See* Direct Testimony of Mr. John F. Devlin, page 16 at 1 to 2.)

Similarly, he simply picks a 2.8 percent standard deviation, inconsistent in time with his ratio and the third highest calculation he made. Finally, he uses a twelve-month average of long-term risk-free rates that is inconsistent with Mr. Devlin's short-term data calculations and not current with the current cost of capital. Fixed-income securities such as U.S. Treasury securities typically have higher rates as maturities increase, exhibiting an "upward sloping yield curve." The yield curve is currently upward sloping so the long maturity would lead to a high risk-free rate.

Mr. Devlin concludes that the allowed ROE to the industry should be 11.91 percent. He then adjusts this mean allowed ROE for APS based on his forecast ability from a twelve-variable regression.

Mr. Devlin's Regression Adjustment Process

Q. PLEASE DESCRIBE IN GENERAL TERMS HOW MR. DEVLIN ADJUSTED HIS 11.91 PERCENT INDUSTRY ROE FOR APS?

A. Mr. Devlin calculated a dispersion of allowed ROEs across his companies and chose to put APS in a band associated with moderate operating risk. APS apparently ranked 89 out of his 113 companies. He calculates that this risk position puts APS in the 11.18 percent to 11.40 percent region without specifically describing his calculations. He then developed a pro forma risk profile that effectively raised APS' risk ranking from the 89th most risky to the 75th most risky of the 113 companies. This action boosted his cost of equity range to 11.44 percent to 11.66 prcent. This range is his final recommendation

Q. IS THE DISPERSION APPROPRIATE TO USE IN THIS PROCEEDING?

A. No. Mr. Devlin's dispersion is not appropriate to use in this proceeding. He apparently calculated this difference between the highest and lowest ROE in any given year for the years 1994 through 2003. He then averaged those differences over time. The first problem is that he is not measuring costs of equity, but rather allowed ROEs. A second problem is that the Idaho Commission has no way of examining what drivers were behind those high or low allowed ROEs or how comparable they might be to APS. For example, the highest ROE might have been allowed to a utility with high percentage of debt and the lowest ROE allowed to a utility with a small percentage of debt, consistent with the CAPM. However, Mr. Devlin is recommending that APS' allowed ROE be increased above the average even though it has about the same percentage of equity as the average electric utility.

Q. IS MR. DEVLIN'S REGRESSION AN APPROPRIATE MANNER TO ASSESS RISK?

A. No. Mr. Devlin's proprietary regression is not an appropriate manner to assess risk. First, his regression attempts to predict RORs based on accounting data. His regression does not model the cost of equity, which is the variable one would need to adjust a sample average cost of equity. His regression's twelve predictive variables appear inconsistent with modern corporate finance theory and the CAPM. We know from the CAPM that investors do not expect to be compensated for risks that they can eliminate through portfolio diversification. Many of the twelve variables appear diversifiable, such as weather, purchased

SAMPLE

power, and test year construct. The regression appears arbitrary, lacking support from any capital markets theory, and inconsistent with the CAPM. Therefore, any use of the model would also be arbitrary and inconsistent with finance theory.

Q. IS MR. DEVLIN'S PRO FORMA ADJUSTMENT TO HIS REGRESSION RESULTS APPROPRIATE?

A. No. Mr. Devlin arbitrarily altered his regression results to increase APS' apparent risk according to his model.

Q. ULTIMATELY, HOW DID MR. DEVLIN RANK HIS COMPANIES FOR RISK AND WHAT DOES THAT RANKING MEAN?

A. Mr. Devlin ranked his companies by how well his regression predicted their accounting RORs. He determined that the companies for which his model could least explain accounting RORs would be ranked higher in risk. Therefore, Mr. Devlin determined a utility's risk based on how well his proprietary model could predict that utility's accounting ROR's. His results are not so much a determination of equity risk as they are an assessment of his regression's ability to predict accounting RORs. His process is not an appropriate manner to assess the risk of common equity as determined in the capital markets.

Conclusion

Q. WHAT DO YOU CONCLUDE GIVEN THE EVIDENCE YOU REVIEWED?

A. I conclude that Mr. Devlin's OPERA method misapplies a Sharpe Ratio analysis that is subsequently increased based on the ability of a proprietary Ernst & Young

regression to predict accounting RORs. The Sharpe ratio was developed and used to compare performances of different mutual funds over time. The Sharpe Ratio is not used to estimate the cost of equity to a company at a point in time. I also found that not only did Mr. Devlin misapply the Sharpe Ratio but he miscalculated every element of it. I also found that his regression analysis is inconsistent with corporate finance theory and inappropriate.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

RECEIVED
NOV 24 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

Conflict of Interest Disclaimer

AFFIDAVIT OF JOHN S. THORNTON, JR.

RECEIVED
NOV 2 4 2004
ND PUBLIC SERVICE COMMISSION
EXECUTIVE SECRETARY

STATE OF ARIZONA)
)ss.
County of Maricopa)

John S. Thornton, Jr., being first duly sworn upon oath, states deposes and says:

1. I am the Principal of Thornton Financial Consulting.

2. My firm has not worked for Xcel Energy, Northern States Power Company, or their affiliates.

3. I am unaware of any other conflicts of interest that would prevent Thornton Financial Consulting from working on behalf of the North Dakota Public Service Commission in NDPSC Case No. PU-04-578.

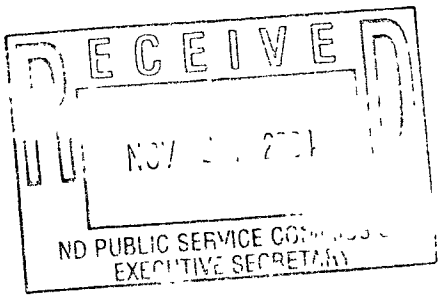
John S. Thornton, Jr.
Principal, Thornton Financial Consulting

SUBSCRIBED AND SWORN TO before me this 22 day of November, 2004.

OFFICIAL SEAL
CAROLYNN D. FREYE
Notary Public - State of Arizona
MARICOPA COUNTY
My Comm. Expires July 7, 2005

By _____
Notary Public

My Commission Expires: July 7, 2005



Letter of Reference

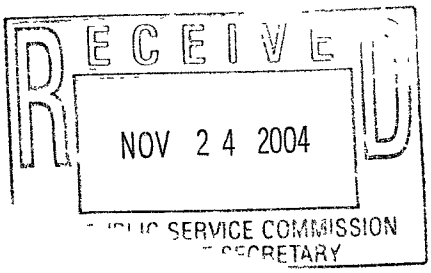
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Executive Secretary

Phone No.: 602-542-3933
Fax No.: 602-542-5560
e-mail: mspitzer@cc.state.az.us

ARIZONA CORPORATION COMMISSION



April 5, 2004

RE: Letter of Reference for John Thornton

To Whom It May Concern:

I have had the opportunity to work with John Thornton since January 2001 after being elected to the Arizona Corporation Commission. John was the Supervisor in the Finance and Regulatory Analysis Section in our Utilities Division. His analysis was detailed, concise, thorough and very helpful in the decision making process on rate cases.

John is very intelligent and well-versed in accounting and finance issues. I strongly recommend him to any position in the utility rates and finance field.

Please call me at (602) 542-3933 if you have any questions.

Very truly yours,

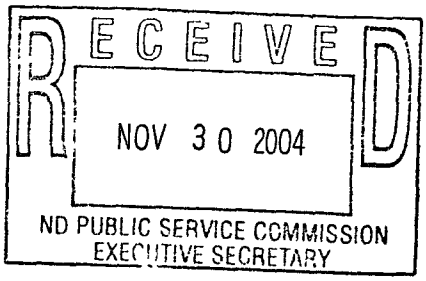
Marc Spitzer
Chairman

Doherty & Company, Inc. Consultants to Management

545 South Prospect St • Suite 22
Burlington, Vermont 05401
Tel 802-864-1684
Fax 802-864-0641

DCI

November 24, 2004



Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 E. Boulevard Ave, Dept. 408
Bismarck, North Dakota 58505-0480

Dear Ms. Jeffcoat-Sacco,

Doherty & Company, Inc. (DCI) appreciates receiving the Request for Proposal (RFP) in Case No. PU-04-578, to assist in the investigation of Northern States Power Company's gas rate increase request.

Our present work load is such that we do not plan to submit a proposal in response to this request. We request that you retain DCI's name on your consultants list. We look forward to other opportunities to serve you in the future.

We have taken the liberty of forwarding this RFP to Utilitech, Inc., a consulting firm with which we have worked in the past, in the event they have not already received it.

Cordially,

Philip A. Doherty

9 PU-04-578 Pages 1

not submitting a bid proposal

by Doherty & Company, Inc

2004omm Legal Jerry Amen Pat Jerry Amen Mike

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DOCKET SEQUENCE NO. _____

EXHIBIT _____

CASE NO. PU - 04 - 578

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