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May 25, 2006

Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way, Suite 7
Lansing, MI 48911

Re: SEMCO Energy Gas Company
2006 Rate Case
MPSC Case No. U-14893 (Paperless)

Dear Ms. Kunkle:

Attached for filing are an Application and supporting testimony and exhibits of Eugene N. Dubay, Annette Gardiner, Bruce H. Fairchild, John R. Alger, Steven W. Warsinske, Malcolm R. Ketchum, James A. Van Sickle, Rick L. Ayers, Daniel J. Forsyth, James C. Larsen and Timothy J. Lubbers (Volumes I and II).

Also attached is documentation which complies with Part II Additional Information Requirements, of the Rate Case Filing Requirements established in Case No. U-10039 (Volumes III and IV).

Finally, enclosed is a proposed Notice of Hearing which has been emailed to Gloria Jones of your office. In the Notice of Hearing, the Company describes the annual percentage increase of this rate request for a residential customer on a total bill basis (inclusive of commodity costs). SEMCO Gas believes that the typical residential customer reviews his bill in terms of the total amount owed and seeks to avoid customer confusion by describing the increase in terms of the total bill.

Very truly yours,

Sherri Wellman

Digitally signed by Sherri Wellman
DN: CN = Sherri Wellman, C = US, O = Miller Canfield
Date: 2006.05.25 14:24:36 -04'00'

Sherri A. Wellman

SAW/lab
cc: Annette Gardiner

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

NOTICE OF HEARING
FOR THE GAS CUSTOMERS OF
SEMCO ENERGY GAS COMPANY
CASE NO. U-14893

- SEMCO Energy Gas Company may revise its annual natural gas revenues by $18,098,561, if the Michigan Public Service Commission approves its request.

- **A TYPICAL SEMCO ENERGY GAS COMPANY RESIDENTIAL CUSTOMER WHO USES 100 MCF OF GAS PER YEAR MAY SEE AN ANNUAL INCREASE OF $65.18 OR ABOUT A 5.0% INCREASE.**

- The information below describes how a person may participate in this case.

- You may call or write SEMCO Energy Gas Company, 1411 Third Street, Suite A, Port Huron, Michigan, 48060, (800) 624-2019 for a free copy of its application. Any person may review the application at the offices of SEMCO Energy Gas Company.

- The first public hearing in this matter will be held:

DATE:	_____, 2006 This hearing will be a pre-hearing conference to set future hearing dates and decide other procedural matters.
TIME:	9:00 a.m.
PRESIDING OFFICER:	Administrative Law Judge _____
LOCATION:	Michigan Public Service Commission 6545 Mercantile Way, Suite 7 Lansing, MI 48911
PARTICIPATION:	Any interested person may attend and participate. Persons with disabilities, needing help to participate, should call the Commission's Executive Secretary at (517) 241-6160 a week in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission will hold a public hearing to consider the May 25, 2006 application of SEMCO Energy Gas Company (SEMCO Gas) to redesign rates and increase revenues for the sale, transportation and distribution of natural gas. SEMCO Gas seeks to charge the following rates:

Service Class	Monthly Service Charge
Residential	$24.09

General	Monthly Customer Charge	Distribution Charge Per Mcf
GS-1	$12.00	$1.7852
GS-2	$50.00	$1.2060
GS-3	$100.00	$1.0537

Transportation		Transportation Charges per Mcf	
		On-Peak	Off-Peak
TR-1	$450.00	$0.8179	$0.6679
TR-2	$1,050.00	$0.6827	$0.5327
TR-3	$3,075.00	$0.6113	$0.4613

As part of its rate redesign proposals, SEMCO Gas seeks to (i) replace the residential monthly customer charge and the volumetric distribution charge with a single fixed residential monthly service charge, or alternatively, only replace the volumetric distribution charge with a fixed residential monthly service charge and retain a separate residential monthly customer charge; (ii) remove Lost and Unaccounted For ("LAUF") gas costs from base rates and collect LAUF gas costs as a booked cost of gas sold through the GCR process; (iii) alternatively, retain LAUF gas costs in base rates at an appropriate level and "true up" this amount to match the Company's actual LAUF gas costs on an annual basis; (iv) "true up" the amount of Uncollectible Expense in base rates to match the Company's actual Uncollectible Expense on an annual basis; and (v) implement surcharges to recover costs associated with: (a) a residential conservation program and participation in Michigan's Low Income Energy Efficiency Fund, and (b) an accelerated program for replacement of unprotected and bare steel mains and compressors.

The Commission has selected this case for participation in its Paperless Electronic Filings Program. All documents filed in this case shall be submitted electronically through the Commission's Electronic Case Filings Web site at: https://efile.mpsc.cis.state.mi.us/cgi-bin/efile/login.pl. Requirements and instructions for filing electronic documents can be found in the Electronic Filings User Manual at: http://efile.mpsc.cis.state.mi.us/efile/usersmanual.pdf.

An application for account and letter of assurance, required of all first-time users, is located at: http://efile.mpsc.cis.state.mi.us/efile/pdfs/assurance.pdf. Documents may also be submitted in Word format, as an attachment to an email sent to mpscefilecases@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 241-6170 or by e-mail at mpscefilecases@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____, 2006. (Residential customers may file petitions to intervene using the traditional paper format.) The proof of service shall indicate serving upon SEMCO Gas's attorney: Harvey J. Messing, Miller, Canfield, Paddock and Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, MI 48933.

Any person wishing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his/her wish to make a statement of position.

A copy of SEMCO Gas's request may be reviewed on the Commission's Web site at http://efile.mpsc.cis.state.mi.us/efile, or at the office of the Commission's Executive Secretary, 6545 Mercantile Way, Suite 7, Lansing, MI, and at the office of SEMCO Energy Gas Company, 1411 Third Street, Suite A, Port Huron, MI. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 241-6170.

Jurisdiction is pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 19393 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1999 AC, R 460.17101 et seq.

SEMCO ENERGY GAS COMPANY HAS REQUESTED THE INCREASES DESCRIBED IN THIS NOTICE. THE MICHIGAN PUBLIC SERVICE COMMISSION MAY GRANT OR DENY THE REQUESTED INCREASES AND OTHER PROPOSALS, IN WHOLE OR IN PART, AND MAY GRANT LESSER OR GREATER INCREASES THAN THOSE REQUESTED, AND MAY AUTHORIZE A LESSER OR GREATER RATE FOR ANY CLASS OF SERVICE THAN THAT REQUESTED.

_____, 2006

Lansing, Michigan

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for sale and transportation of	)	[e-file]
natural gas in its MPSC Division and	)	
other relief.	)	

APPLICATION

Now comes SEMCO ENERGY GAS COMPANY ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc., and hereby requests authority to (i) change, or redesign, the way in which the Company charges customers for natural gas service, and (ii) increase rates for the sale, transportation and distribution of natural gas in its service territory currently subject to the ratemaking jurisdiction of the Michigan Public Service Commission (the "MPSC Division") and for other related approvals and relief. In support of this Application, the Company respectfully represents to the Michigan Public Service Commission (the "Commission" or "MPSC") as follows:

I. INTRODUCTION

1. SEMCO Gas is a division of SEMCO Energy, Inc., with its principal offices located at 1411 Third Street, Suite A, Port Huron, Michigan. The Company is engaged as a public utility in the business of selling, transmitting, and distributing natural gas to the public in its various service areas throughout the State of Michigan, including the MPSC Division. The Company serves approximately 240,000 residential, commercial and industrial customers in the MPSC Division, with residential customers comprising approximately 90% of its customer base. The MPSC Division is comprised of various non-contiguous areas in Michigan, including areas in and around Port Huron, Richmond, Chesterfield, Sandusky, Romeo, Albion, Niles, Three Rivers, Holland, St. Ignace, Newberry, Engadine, Manistique, Marquette, Negaunee, Houghton and Ontonagon.

2. SEMCO Gas's retail natural gas business is subject to the jurisdiction of the Commission pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq. Pursuant to these statutory provisions, the Commission has jurisdiction to regulate the Company's retail natural gas sales, transportation and distribution rates. This includes jurisdiction over the ways in which such rates are designed to provide the Company with a fair opportunity to recoup the costs of providing service to its customers.

3. SEMCO Gas's last base rate case was Case No. U-14338. That case was concluded by Commission Order dated March 29, 2005, and the base rates established in that case were based on an adjusted test year ending December 31, 2005, and an authorized rate of return on common equity of 11.00%. The Company also recovers its booked cost of gas sold pursuant to its GCR Cost Recovery ("GCR") clause as authorized by the Commission pursuant to 1982 PA 304, MCL 460.6h et seq.

4. This Application is accompanied and supported by the written testimony and exhibits of eleven witnesses. The Company's presentation in this case was prepared in accordance with the standardized filing requirements established by the Commission's Order in Case No. U-10039.

II. REQUESTED RATE INCREASE

5. Because the (i) costs of providing service to MPSC Division customers have increased, and (ii) SEMCO Gas has not realized previously-authorized base rate increases, due, in large part, to a substantial and continuing decline in per customer natural gas usage, the Company's existing retail rates for natural gas services are unreasonably low and inadequate. SEMCO Gas has not earned its authorized return on common equity since its last rate increase in Case No. U-14338. In fact, in 2005, SEMCO earned a 6.4% rate of return on the equity investments made by its shareholders, compared to an MPSC-authorized return on equity of 11.00%.

6. This rate filing presents data for a historical year 2005, as required under Section A of the standardized filing requirements established by the Commission's Order in Case No. U-10039. SEMCO Gas proposes, that rates be established based upon a test year ending December 31, 2007, adjusted for known and measurable changes in the costs of providing service to customers. Use of this adjusted test year data should allow the base rates established in this case to more closely reflect conditions that will likely exist at and after the time the rates set by the final order in this case are placed in effect.

7. Several factors have, and are expected to continue to have, a significant impact upon the Company's costs of providing service to MPSC Division customers as reflected in its revenue requirement and base rates, rendering existing rates unreasonably low and inadequate and precluding the Company from earning a reasonable return on its investments used and useful in providing service to customers. Among other items, SEMCO Gas's existing rates established in Case No. U-14338 do not reflect recent increases in (i) inflation, (ii) operations and maintenance ("O&M") expenses, including the impact of MPSC billing rule changes, the increased cost of employee medical and dental benefits, and pension and retiree medical expenses, (iii) working capital costs associated with gas storage, and (iv) necessary capital investments. The level of capital investment (such as a new Customer Information System) and O&M expenses necessary to maintain, strengthen, and expand the existing natural gas transportation and distribution system and to assure safe and reliable service to customers have increased significantly beyond the levels currently reflected in the Company's base rates. Another important factor contributing to the Company's revenue shortfall, as will be further addressed in Section III of this Application, is declining per customer use of natural gas, including the effects of conservation. These and other factors, as described in more detail in the supporting testimony and exhibits, necessitate an increase in SEMCO Gas's current retail natural gas rates.

8. Unless timely rate relief is granted by the Commission, the Company will experience a revenue deficiency of $18,098,561 in 2007. This 2007 test year revenue

deficiency represents the results of a complete examination of the relevant items of investment, expense, and revenues for the determination of just and reasonable SEMCO Gas retail natural gas rates for its MPSC Division customers.

9. SEMCO Gas proposes that retail natural gas rates be established which reflect an overall rate of return on total rate base of 8.23% and a rate of return on common equity of 11.90%. The capital structure ratios used by the Company are based upon an industry average capital structure previously employed by the Commission in setting the Company's base rates.

10. SEMCO Gas represents that, without taking into account the rate design changes proposed by the Company, the proposed rate increase of not less than $18,098,561 annually is required in order for the Company to maintain an adequate, reliable, and safe natural gas transportation and distribution system and to allow SEMCO Gas a reasonable opportunity to earn the return to which the Company is entitled by law.

III. PROPOSED IMPROVEMENTS IN RATE DESIGN

11. A sharp and continuing decline in natural gas use per customer is a major cause for Company's revenue shortfall and inadequate earnings over the last several years. Actual use per customer is substantially below levels used to establish rates in Case No. U-14338, and this difference between the Company's actual experience and the assumptions used to establish the Company's base rates has adversely affected the Company's collection of revenues through its volumetric distribution rates. In sum, the Company's existing rate design, which provides for the recovery of fixed costs through a combination of fixed charges and volumetric distribution rates based on estimates of customer natural gas use, effectively precludes the Company from earning sufficient revenues to cover the cost of providing service to customers, including a reasonable return on its investments, used and useful, in providing such service. In addition, given the way in which SEMCO Gas is currently compensated in base rates for certain costs, the Company's ability to earn sufficient revenues to cover those costs of providing service to customers has also been adversely affected by substantial increases in the market price for natural gas and other factors.

12. In this case, the Company is proposing that the Commission adopt a different rate design for the Company, including: (i) on a permanent or pilot program basis, depending on the Commission's preferences, replacing the residential monthly customer charge and the volumetric distribution charge with a single fixed residential monthly service charge, or alternatively, only replacing the volumetric distribution charge with a fixed residential monthly service charge and retaining the separate residential monthly customer charge; (ii) removing Lost and Unaccounted For ("LAUF") gas costs from base rates and collecting LAUF gas costs as a "booked cost of gas sold" through the GCR rate (subject to annual MPSC review as part of the GCR process); (iii) alternatively, retaining LAUF gas costs in base rates at an appropriate level and "truing up" this amount to match the Company's actual LAUF gas costs on an annual basis; and (iv) "truing up" the amount of Uncollectible Expense allowed in base rates to match the Company's actual Uncollectible Expense on an annual basis. The Company is also seeking, as more fully described in the testimony and exhibits of its witnesses, Commission approval of separate funding proposals for (i) a residential conservation program called "This Cold House" and participation in Michigan's Low Income Energy Efficiency Fund ("LIEEF"), and (ii) an accelerated program for replacement of unprotected and bare steel mains and compressors.

13. An important feature of the Company's proposed fixed monthly service charge rate design is that it supports a pro-conservation public policy, by aligning customer and Company interests with respect to the conservation of natural gas by customers. As noted, as part of its request that the Commission approve certain rate design changes, SEMCO Gas is proposing to implement a comprehensive residential customer efficiency and conservation program called "This Cold House" and participate in LIEEF. This proposal is consistent with Staff's report on energy efficiency issued in Case No. U-14667. The Company proposes that these conservation efforts be customer supported through a separate surcharge. In order to avoid the ratemaking complexities associated with issues such as conservation program-drive lost sales, SEMCO Gas proposes that Commission approval of a Company-sponsored

conservation program and LIEEF participation be contingent upon Commission adoption of the residential fixed monthly service charge rate design proposed by the Company. This rate design would make SEMCO Gas indifferent financially to conservation resulting from implementation of these proposed programs, but supportive of conservation from a public policy perspective.

14. The Company is also proposing that the Commission permit SEMCO Gas to collect certain capital costs associated with the accelerated replacement of certain unprotected and bare steel mains and compressors. In view of the Company's (i) relatively small size and financial condition, (ii) its already substantial capital spending program, and (iii) the non-revenue producing nature of these needed projects, it would be an appropriate exercise of ratemaking discretion for the Commission to authorize the Company to collect the capital-related costs on these projects before they are placed in rate base.

15. Furthermore, the Company is proposing, among other things, to establish interruptible transportation rates, revisions to its general rules, and to revise, or implement, charges for certain services. This other relief sought by SEMCO Gas is more fully described in the accompanying testimony and exhibits. The relief more fully described in the testimony and exhibits is an integral part of this Application and should be considered as if specifically requested in this Application.

IV. RESERVATION OF RIGHT TO AMEND

16. In addition to the matters described in the preceding paragraphs, it is possible that other pending or to be filed proceedings or events may affect the determination of just and reasonable base rates for the Company.

17. SEMCO Gas therefore reserves the right to revise, amend, or otherwise change this Application in any way it deems appropriate or desirable to ensure that the Commission is able to determine just and reasonable rates for the Company.

V. PROPOSED SCHEDULE

18. Consistent with the legislative policy reflected in MCL 460.6a(2) and because of the importance of this case to SEMCO Gas, the Company respectfully requests that the Commission adopt a nine-month schedule for this proceeding. Attached as Attachment 1 hereto is a proposed schedule, which, if adopted by the Commission, will result in compliance with the nine-month requirement set forth in MCL 460.6a and the speedy determination of issues of substantial importance to the Company.

VI. REQUEST FOR RELIEF

19. SEMCO Gas's presently-effective retail rates for the sale, transportation and distribution of natural gas are now, and in the future will continue to be, unjust and unreasonable. Such rates are not sufficient to permit the Company to recoup the costs of providing service to its MPSC Division customers, including a reasonable return on investments used and useful in providing such service, to which SEMCO Gas is entitled by law. SEMCO Gas's retail natural gas rates are, and are expected to remain, so low as to deprive it of a reasonable return on its property and to amount to confiscation of the Company's property contrary to SEMCO Gas's rights under the Constitution of the United States and the Constitution and laws of the State of Michigan. The inadequacy of these natural gas rates reduces the Company's revenues and overall rate of return below a proper and reasonable level, and it is unjust and unreasonable to require SEMCO Gas to render natural gas service to its customers at such rates.

WHEREFORE, SEMCO Energy Gas Company requests the Commission to:

A. Issue and publish its Notice of Hearing setting an early hearing date;

B. Adopt the schedule set forth in Attachment 1 hereto;

C. Find and determine that existing rates and charges are unreasonably low and inadequate and should be increased to protect the constitutional rights of the Company to earn a reasonable and non-confiscatory return;

D. Authorize the Company to adjust its existing rates and charges so as to produce additional revenue of not less than $18,098,561 annually, without taking into account the rate design changes proposed by the Company;

E. Redesign rates as requested in this Application and addressed in the supporting testimony and exhibits;

F. Authorize all other changes and suggestions made and supported in the Company's testimony and exhibits; and

G. Grant such other further relief as may be lawful and proper.

Respectfully submitted,
SEMCO ENERGY GAS COMPANY

Dated: May 25, 2006 By: Sherri Wellman Digitally signed by Sherri Wellman DN: CN = Sherri Wellman, C = US, O = Miller Canfield Date: 2006.05.25 13:01:19 -04'00'

One of Its Attorneys
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P.O. Box 5004
Port Huron, MI 48060-5026

LALIB:141996.1\129584-00014

ATTACHMENT 1

PROPOSED SCHEDULE

SEMCO ENERGY GAS COMPANY
2006 Rate Case
MPSC Case No. U-14893

1.	Staff & Intervenor direct case filing	August 25, 2006
2.	Rebuttal Testimony	September 25, 2006
3.	Motions to Strike	October 16, 2006
4.	Cross Examination	October 23-27, 2006
5.	Briefs	November 20, 2006
6.	Reply Briefs	December 6, 2006
7.	PFD Target Date	January 17, 2007
8.	Exceptions	February 8, 2007
9.	Replies to Exceptions	February 22, 2007
10.	Expected Order	March 2007

7 calendar day turnaround (or best efforts) from the date of service.

MICHIGAN PUBLIC SERVICE COMMISSION

CASE NO. U- 14893
Date 25-May-06

GENERAL APPLICATION FOR
CHANGE IN GAS UTILITY RATES
BEFORE MICHIGAN PUBLIC SERVICE COMMISSION
CLASS A & B UTILITIES

COMPANY NAME: SEMCO Energy Gas Company

ADDRESS: 1411 Third, Suite A, Port Huron MI 48060

TELEPHONE: AREA CODE 810 NUMBER 887 - 4227

COMPANY OFFICIAL TO BE CONTACTED
PERTAINING TO RATE CASE MATTERS: Annette Gardiner

FILING DATE: 25-May-06

TITLE OF AUTHORIZED OFFICER: Regional Vice President - Technical Services

*** COMMISSION ONLY ***

DATE RECEIVED BY COMMISSION:

DOCKET NUMBER ASSIGNED:

RECEIVED BY:

DATE ACCEPTED:

ACCEPTED BY:

NOTIFICATION DATE(S):

SCHEDULED PRE-HEARING DATE:

SEMCO Energy Gas COMPANY

CERTIFICATION OF STEVEN W. WARSINSKE

Steven W. Warsinske, Vice President and Controller of SEMCO Energy, Inc., states that he has provided the data required pursuant to Part II, of the Michigan Public Service Commission's Rate Case Filing Requirements for Gas Utilities with Annual Revenues in Excess of $10,000,000 and, pursuant to the Commission's Filing Requirements, certifies the data so provided.

Steven W. Warsinske

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF ANNETTE GARDINER, P.E.

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Annette Gardiner, P.E.
On Behalf of
SEMCO Energy Gas Company

Q. Please state your full name and business address.

A. My name is Annette Gardiner, and my business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position?

A. My title is Regional Vice President – Technical Services for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc.

Q. Please describe your academic background, current job duties, and business experience.

A. In 1982, I graduated from Michigan Technological University with a Bachelor of Science degree in Civil Engineering. I also hold an Executive Master's of Business Administration degree from Michigan State University's Eli Broad Graduate School of Management (May 2003). Additionally, I am a registered professional engineer in the State of Michigan. In my current position, I direct the activities of employees in rates and regulatory affairs, governmental affairs, engineering, codes and standards, cathodic protection, purchasing, gas control, the meter shop, and incident investigation and claims. I have held positions of increasing responsibility at SEMCO Gas since 1995. Prior to working for SEMCO Gas, I was employed by Michigan Consolidated Gas Company as a transmission engineer.

Q. Have you previously testified before the Michigan Public Service Commission (the "MPSC" or the "Commission")?

A. Yes, my written testimony was included as part of the Company's 2002-03 Gas Cost Recovery plan filing, MPSC Case No. U-13305. Additionally, I have testified in SEMCO Gas's 2002 general rate case, MPSC Case No. U-13575, and as the chief policy witness in SEMCO Gas's 2004 general rate case, MPSC Case No. U-14338.

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

A. As the regulatory policy witness for the Company, I provide an overview of SEMCO Gas's base rate relief request, including the reasons for the requested rate increases for customers in what the Company commonly calls the "MPSC Division". This request does not relate to the Company's rates for its customers in the Battle Creek division, which are currently under the jurisdiction of the City Commission of Battle Creek. My testimony begins with background information on SEMCO Gas's most recent rate case filed in 2004, MPSC Case No. U-14338, then discusses the key elements of this case.

Rate design is an important element of this filing. My testimony addresses the sharp decline in use per customer that SEMCO Gas has experienced, and the corresponding decrease in revenue collection based on volumes of gas consumed by customers. From a rate design perspective, SEMCO Gas is proposing a fixed monthly residential Service charge to collect its residential base rate revenues. As I explain in more detail later in my testimony, use of this revenue collection methodology will afford the Company a reasonable opportunity to earn it authorized rate of return in the current declining use per customer environment and is "pro-conservation," because this way of collecting the Company's residential revenue requirement aligns Company and customer interests with respect to conservation. The Company recognizes that customer communication is an important aspect of changes in rate design and is committed to a comprehensive program for communicating any changes authorized by the Commission in this case.

I also am sponsoring the proposed mechanisms for recovery of lost and unaccounted for ("LAUF") gas costs. The primary objective of the proposed LAUF gas cost recovery mechanisms is to match the Company's recovery of the costs to the actual costs incurred by the Company. I also am sponsoring the Company's proposal for recovery of Uncollectible expense. The changes in cost of gas and the billing rule changes initiated by the MPSC regarding billing rules

have an immediate impact on the Company's bad debt expense. A large proportion of the Company's customers do not understand that the Company does not benefit as commodity costs increase. This is due, in part, to the existing rate design, which includes a monthly distribution charge, calculated on a volumetric basis. Customers tend to believe that the more they consume, the more the Company benefits. The resentment and ill will that is generated by this misinformation is channeled toward the Company and the Commission. Changes in rate design, as proposed, will simplify and clarify for customers the Company's rates and, over time, both the Company and the Commission will benefit from less ill will and fewer complaint calls as customers understand there is no benefit to the Company in the higher commodity, or higher volume, charges. Again, the main purpose of this proposal is to ensure timely and fair recovery of these costs, which are driven primarily by the underlying cost of gas purchased for resale to customers and MPSC-mandated customer billing rules. In my view, the current ratemaking treatment of these items does not provide the Company a fair opportunity to recover these costs of providing service.

In addition, as part of this filing, SEMCO Gas is proposing a funding mechanism for an energy efficiency program ("This Cold House") and the Company's participation in the Low-Income and Energy Efficiency Fund ("LIEEF") program, which addresses the need for energy efficiency programs by promoting conservation and assisting low-income customers in paying their energy bills. I explain the proposed funding mechanism in my testimony, and Mr. Lubbers describes the proposed programs themselves. The Company's basic idea is to use money collected from customers to fund the programs the Commission believes are worthwhile.

My testimony also introduces the Company's proposal for funding the capital-related costs associated with an accelerated program to replace unprotected and bare steel mains and undertake compression improvement

projects. Mr. Larsen describes the program including why unprotected and bare steel main and compressors require replacement on an accelerated schedule in his testimony. Mr. Alger's testimony details the mechanism for recovering the capital-related costs associated with these additional investments, before they are recognized in the Company's base rates.

Finally, I discuss the Company's environmental expenditures and provide a list of witnesses and the topics they will cover.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-11, Schedule F-9	Sample Customer Bills
Exhibit A-8, Schedule B-6	Environmental Expenditures (Including MGP's)

Q. Were these exhibits prepared by you or at your direction?

A. Yes, they were developed under my direction.

Background Information

Q. When did SEMCO Gas last file a general rate case, and what was the outcome in that case?

A. In December of 2004, the Company filed a general rate case designated MPSC Case No. U-14338. In its March 29, 2005 Order in that case, the Commission approved a settlement agreement that, among other things, provided for an estimated annual revenue increase of $7,113,000 based on a test year ending December 31, 2005, and a return on common equity of 11.00%.

Q. Has the Company earned its authorized return on common equity since its last general rate case?

A. No. As explained by the Company's Senior Vice President and Chief Operating Officer, Eugene N. Dubay, SEMCO Gas has not earned its authorized return on common equity since its last general rate case. In fact, despite the Commission's approval of this settlement, the Company's MPSC Division earnings have been substantially below authorized levels.

Q. In general terms, what is your understanding of the company's MPSC Division earnings shortfall, and what are the primary reasons that the regulatory relief ordered in SEMCO Gas's last rate case has proven to be insufficient?

A. In its most recent general rate case, Case No. U-14338, the Company was authorized to earn an 11.0% return on equity. As discussed in Mr. Dubay's testimony, the Company has not earned its authorized return since that case. In fact, based on the Commission Staff's own analysis, the Company's earnings have ranged between 5.5% and 6.3% rate of return on equity from January to September 2005. A similar earnings deficiency is shown by the analysis done for this filing.

Several factors have caused this earnings shortfall, including some cost of service items affected by the recent rise in natural gas prices. In my view, the primary "drivers" for this earnings shortfall include declining use per customer (which is well below levels used to set rates in 2005), LAUF gas costs, Uncollectible expense and working capital requirements. In additions, the Company is facing continuing increases in operations and maintenance ("O&M") expenses, often at rates that exceed inflation.

As described in more detail in Mr. Dubay's testimony, the decline in use per customer, the increase in working capital requirements, and the current ratemaking treatment of LAUF gas costs and Uncollectible expense, and working capital costs all have adversely affected the Company's results. The fact of the matter is that higher and more volatile gas prices have highlighted defects in rate design and the regulatory treatment of certain expenses. From the Company's viewpoint, it is important that the Commission address these elements of the ratemaking calculus constructively, to allow the Company a fair opportunity to earn its authorized rate of return.

Q. Please continue

A. The sharp decline in use per customer and its effect on the Company's collection of revenues through volumetric distribution rates -- unless this decline is properly reflected in the ratemaking process (e.g., via an appropriate ratemaking adjustment to reflect this trend) or a different rate design is used (as proposed in this filing) -- effectively precludes the Company from earning sufficient revenues to cover the costs of providing service to customers, including a reasonable return for shareholders.

Viewed simply, revenue growth has not kept pace with increases in the costs of providing service to customers. Revenue growth has not been sufficient to cover the Company's costs of providing service largely because of a substantial decline in use per customer and weak growth in additional customers. Additionally, as noted, a significant difference between the costs allowed in rates and those actually experienced by the Company are the commodity costs associated with LAUF gas costs, Uncollectible expense, and working capital. The existence of this ratemaking problem has prompted the Company to propose changes in the way the Company recovers these LAUF gas costs and Uncollectible expense.

Q. Is there another aspect of the Company's rate design proposals that, in your view, the Commission should consider?

A. Yes, as discussed later in my testimony and by other witnesses in this case, the Company believes that, from a public policy point of view, it is appropriate to encourage customers to conserve natural gas, especially when prices are substantially higher than in the recent past and there is an apparent imbalance between supply and demand. If conservation is the right public policy for Michigan, however, the Commission should align customer and Company interests, from a ratemaking perspective, so that the Company is not penalized financially for "doing the right thing," from a public policy perspective, by encouraging conservation.

Q. You have discussed some of the primary factors affecting the Company's revenues. What trend has SEMCO Gas seen in other O&M costs since its 2004 rate filing?

A. While inflation is steadily pushing up most costs of providing service to customers, certain costs continue to increase at a rate that outpaces inflation. For example, pension costs have increased from $1.2 million in 2004 to about $1.9 million in 2005 and to an estimated $2.3 million in 2006. The costs of attracting and retaining a qualified workforce continue to grow faster than the underlying inflation rate. Wage increases for management employees in 2005 and 2006 averaged 3.50% and 3.75% respectively. Wage increases for union-represented employees 2005 and 2006 averaged 2.30% and 2.30%, respectively. (The difference in percent wage increase for these two groups of employees was due to lagging non-union employee wages compared to the Company's "middle of the market" target.) This gap was addressed, to some degree, through the higher percentage increases awarded to management employees. In addition, health and dental care costs also continue to outstrip inflation, with medical and prescription drug costs expected to increase by 12.7% and dental costs expected to increase by 5% in 2007, as discussed in Mr. Warsinske's testimony.

Additionally, the Company has invested in new technology to provide customers with better service, to respond more effectively to higher call volumes, and to remove some of the impediments to meeting changing regulatory requirements. As described in Mr. Ayer's testimony, SEMCO Gas has invested, or will shortly invest, a total of about $6.2 million in a new Customer Information System and a total of about $3.7 million in a Field Order System. In addition to the capital investment in these information technology projects, maintenance costs associated with the projects will be approximately $500,000 annually for the

Customer Information System project and about $75,000 annually for the Field Order System project.

Q. What are some examples of the steps SEMCO Gas has taken to mitigate the impact of O&M cost increases since filing its 2004 rate case?

A. Despite an overall increase in O&M costs in 2006 compared to 2005, the Company has worked diligently to keep these costs in check and provide service to customers efficiently. As noted in Mr. Dubay's testimony, SEMCO Gas ranks favorably in American Gas Association metrics on efficiency and O&M cost comparisons. It is especially noteworthy that SEMCO Gas stacks up well when compared to gas companies nationwide because the Company does not serve customers in dense urban areas; nor, because of its relatively small size, does it have the opportunity to achieve certain economies of scale. The ability to identify ways to continue to cut costs year after year diminishes over time, especially when costs have been cut to the lowest point practical in many areas.

That said, as examples of efforts to control O&M costs, the Company has achieved medical and prescription drug costs savings and reduced an already low percentage of Uncollectible expense

Q. What cost saving measures has the Company initiated to reduce medical costs?

A. To mitigate increases in medical costs the Company also applied for, and was accepted into, the Center for Medicare and Medicaid Services (CMS) Retiree Drug Subsidy Program in 2005. Participation in the program allows the Company to receive a subsidy from CMS for prescription drug costs for SEMCO Gas retirees eligible for Medicare.

Also, in 2005, the Company formed a Wellness Committee. The goal of the committee is to enhance the health of the employees and to reduce health care and absentee costs through the support of items such as walking, exercise, and fitness programs, screenings, prevention and education.

Q. What steps has SEMCO Gas taken to mitigate increases in the costs associated with Uncollectible expense?

A. First, I should point out that the cost of natural gas associated with Uncollectible expense is determined by the market price of natural gas, and the Company has no significant degree of control over that portion of Uncollectible expense. That said, the Company is proactive in addressing bad debts, in terms of trying to limit the number of customers who become delinquent on their accounts and the amount of these arrears. In cases where no resolution with the customer is negotiated, gas service to customers who are over $50 in arrears on their accounts is shut-off. Similarly, efforts are made to reduce past due accounts by disconnecting customers prior to their incurring a balance that is several months in arrears. At the same time, SEMCO Gas also works with customers to put them in touch with local agencies that may be able to assist them in paying their bills for service. The Company also abides by the MPSC's service shut-off rules, which I will address later in my testimony. These efforts reduced the percentage of Uncollectible expense from 0.44% of sales in 2004 to 0.41% of sales in 2005 (on sales of $319,949,480 and $387,767,450 in 2004 and 2005, respectively). Even though the percentage of bad debts decreased, the Company's overall Uncollectible expense increased, due to the substantial increase in cost of gas during this same period.

Overview of Proposed Base Rate Increase and Rate Design Proposals

Q. Please summarize SEMCO Gas's proposed annual base revenue increase.

A. SEMCO Gas is requesting an annual base revenue increase of $18,098,561 at an 11.9% authorized return on equity sponsored by Dr. Fairchild. This proposed annual revenue increase is based on a historical year ending December 31, 2005, with adjustments for known and measurable changes necessary to make 2005 data representative of conditions during test year 2007,

which is the rate effective period. Unless current rates are adjusted, the Company will not have a fair opportunity to recoup its costs of providing service to customers, including a reasonable return on its investments.

SEMCO Gas has generally used methodologies preferred by the Commission's Staff in analyzing the Company's need for rate relief. The Company also has identified instances where it has proposed to depart from those methodologies. These methodologies include weather normalization based upon the National Oceanic and Atmospheric Administration's ("NOAA") 30-year normal weather, a 2005 historic year adjusted for known and measurable changes to develop a 2007 test year, and a Cost of Service Study, all modeled on the Commission Staff's approach.

Q. Please summarize the Company's rate design proposals.

A. Rate design, or the manner in which revenues are collected, is a key element in this request. Taking into consideration the sharp and continuing decline in use per customer and the importance of aligning Company and customer interests with respect to conservation, the Company is seeking to eliminate the non-Gas Cost Recovery ("GCR") volumetric component of residential rates (which is sometimes known as the distribution charge). Instead, the Company proposes to recover all its costs of providing service to residential customers in a single fixed monthly service charge. As discussed in more detail below, this "decoupling" breaks the link between revenue collection and the consumption of natural gas by customers in a manner that is easy to understand. To my way of thinking, the Company's residential customer bill reflecting this new rate design (see page 2 of Exhibit A-11, Schedule F-9, "Sample Customer Bills") will be simpler, since customers will pay one charge that covers the Company's costs of providing service, including the cost of capital, and separate GCR charges for natural gas they consume. This approach also removes the financial disincentive the Company otherwise would have for promoting conservation. As noted in SEMCO

Gas's comments to the Commission in Case U-14667, the Commission's own docket to explore options for encouraging energy efficiency, the Company agrees with the Commission that aligning stakeholder interests to promote energy efficiency is an important goal for customers, utilities, and the economy in the State of Michigan. The Company's proposed rate design accomplishes this objective of aligning Company and customer interests, while ensuring that each customer still receives an accurate price signal, in the form of the GCR portions of the bill reflecting the customer's actual consumption of natural gas each month. It is worth noting that promoting energy efficiency encourages customers to conserve, and there are two kinds of savings associated with such reduced usage. The primary benefit to customers from conservation is reduced volumetric commodity costs. There is also the potential, moreover, for a reduction in the price of commodity itself, as conservation affects supply/demand/price relationship.

Q. Please discuss the Company's other major rate design proposals.

A. The Company proposes changes in the way in which it collects the costs associated with LAUF gas and Uncollectible expense. Briefly, SEMCO Gas is requesting that (1) LAUF gas costs be removed from base rates and collected in the GCR process, or (2), alternatively, the Company be permitted to "true-up" the amount allowed in base rates and actual LAUF gas costs on an annual basis. The Company is also requesting an annual true-up for actual Uncollectible expense.

The Commission's current methodologies do not allow the Company the ability to recover these costs of serving customers, particularly when the cost of natural gas has increased substantially and price volatility has increased, as SEMCO Gas has experienced recently. Using 5-year averages and then-current prices in the case of LAUF gas costs to determine a "normalized" cost level for base rates reasonably approximates a utility's actual experience when the cost of

natural gas and the other drivers of these expenses are relatively stable. When the cost of natural gas moves sharply higher and becomes more volatile, "normalized" cost levels should not be used, largely because the normalized level is likely to be so different from the utility's actual experience. Instead, as discussed in more detail below, the Company submits that the appropriate rate design is one in which these costs are matched more closely to the Company's actual experience.

Q. Please discuss the conservation-related and other programs that the Company is proposing in this filing.

A. The Company is proposing a conservation program and participation in LIEEF, and an accelerated replacement program for unprotected and bare steel and compressors. These programs, including the Company's funding proposals, will be fully described in my testimony and in the testimony of other witnesses in this case.

Rate Design – Fixed Monthly Service Charge

Q. Describe in more detail how SEMCO Gas proposes to collect its base rate revenue from residential customers?

A. SEMCO Gas is requesting a rate design that "decouples" its revenues from the volumetric consumption of its customers. The method that the Company is proposing is a fixed monthly service charge that recovers all the fixed costs of providing service to customers. This includes the costs of preparing and transmitting customer bills, interacting with customers over the telephone and in-person (such as on service calls), maintaining meters, regulators, service lines, transporting gas to the customer, and including the cost of capital – in sum, everything needed for a residential customer to receive natural gas from the Company's system for use in a home and for the Company to interact with that customer about his or her natural gas service.

Q. How much is the proposed service charge?

A. SEMCO Gas is proposing a $24.09 per month fixed residential service charge. This charge would replace the monthly customer charge (currently $9.50) and monthly distribution charge (currently $1.2230 per thousand cubic feet ("Mcf") of usage). The new fixed monthly service charge includes the costs associated with serving residential customers that were formerly collected through these two charges and does not include LAUF gas costs

As previously mentioned, the Company is proposing to remove LAUF gas costs from base rates, or alternatively, to "true-up" the amount allowed in base rates and actual LAUF costs on an annual basis. If LAUF gas costs are included in base rates in the final MPSC decision in of this case, the proposed fixed monthly residential service charge proposed would be $25.18. This amount includes the increase required by the current revenue deficiency, including the collection of LAUF gas costs.

Q. Would the Company consider collecting the fixed costs associated with serving its residential customers in two fixed charges?

A. Yes. Fixed costs could be collected in a fixed monthly customer charge of $9.50 and a monthly service charge of $14.59 (or $15.68 including LAUF gas costs). See Exhibit A-11, Schedule F-9 (page 3) for a sample customer bill showing these charges.

Q. Why is SEMCO Gas proposing a fixed monthly service charge?

A. The primary reasons for this request are to: (1) align Company and customer interests with respect to conservation, by eliminating the Company's financial disincentive to promote conservation that results from collecting the Company's costs of serving customers in a volumetric rate (i.e., with a volumetric rate, Company revenues increase when customers use more natural gas and decrease when they use less gas for any reason); (2) "levelize" the Company's collection of its costs, again by eliminating a volume-based distribution charge that is highest in the winter heating season when customers consume the most

natural gas and therefore experience the highest bills; (3) address, other than by a prospective sales adjustment, the effect of a substantial and continuing decline in use per customer on the Company's collection of its revenue requirement (which, in turn, should reduce the need for future rate case filings driven by that apparent trend); (4) provide customers with a bill that is easier to understand, because volumetric recovery of the Company's revenue requirement (the distribution charge) will be eliminated; and (5) clarify for customers the fact that the Company makes no additional money on a customer's consumption of natural gas when the weather is cold and volumes consumed are high. Additionally, the collection of fixed costs through fixed charges reflects a sound economic principle and is appropriate for other reasons that are addressed in Mr. Ketchum's testimony.

Q. Why is SEMCO Gas proposing a fixed monthly service charge instead of other means for "decoupling" revenues and consumption?

A. There are many methods that may be used to achieve the decoupling of utility revenues from customer consumption. The Company believes that a fixed service charge is the best overall decoupling methodology for the Company at this time, primarily because:

1. A fixed monthly charge is easy for customers to understand (see page 1 of Exhibit A-11, Schedule F-9, "Sample Customer Bills") that shows an existing residential customer bill (with a monthly customer charge and distribution charge) compared to a sample residential customer bill (with a fixed service charge, see page 2 of Exhibit A-11, Schedule F-9). The bill would clearly differentiate the costs of the Company's providing service from the cost of the natural gas consumed by the customer. In that sense, the proposed bill makes it clear that the Company does not profit on the gas commodity, or GCR, portion of the bill, since all of the Company's costs (including its return on investment) are part of the $24.09/month fixed service charge. Under the Company's current rate

design, a utility collects more revenue to cover fixed costs when customers use more gas and less revenue to cover fixed costs when customers use less gas. So, it is understandable given how they are charged that some customers find it difficult to believe that the Company is not "profiting" on the gas they consume.

2. Fixed monthly charges are familiar to, and accepted by, customers. It should be kept in mind that customers are already familiar with many forms of fixed charge bills, such as bills for internet service and cellular phone usage. I discuss this topic in more detail later in my testimony.

3. A fixed monthly service charge is a simpler, lower cost method to achieve the same "pro-conservation" public policy objectives that other decoupling mechanisms are designed to address, in terms of regulatory oversight, customer accounting complexity, and billing system information technology changes.

4. Residential customers would no longer "overpay" for the cost of Company-provided gas delivery services in colder-than-normal winters and "underpay" for those services in warmer-than-normal winters, because a portion of the charges on their bills are based on volumes of natural gas consumed. By definition, since there is a volumetric component in the Company's current rate design, the collection of its base rate revenue requirement is affected by the weather. Because of the resulting effects on revenue collection, and putting aside other factors affecting usage, the Company "over-collects" its revenue requirement in colder-than-normal winter heating seasons and "under-collects" its revenue requirement in warmer-than-normal periods. Under the Company's proposed fixed monthly service charge rate design, the volumetric component is eliminated, and thus this weather-driven variation in revenue collection will no longer occur.

5. Customer bills would be more stable, since a larger portion of the total bill would be fixed each month and would not be dependent on changes in

weather or usage patterns. That said, as Mr. Ketchum confirms, customers would still receive an appropriate price signal, based on their consumption of natural gas, because they would be charged in the GCR portion of their bill for their actual usage.

6. Eliminating the monthly volumetric distribution charge and collecting the Company's base rate revenue requirement in a fixed monthly service charge means that clearer information and price signals would be sent to customers interested in evaluating Customer Choice options.

7. The length of time between rate cases would likely be extended, at least to the extent that delivery service revenue losses were due to the current trend in declining natural gas use per customer.

Q. Is SEMCO Gas proposing a fixed monthly service charge for all customer classes? If not, why not?

A. No. SEMCO Gas is proposing a fixed monthly service charge only for residential customers. The Company proposes that, at this point in time, other customer classes continue to be charged a monthly customer charge and separate distribution and GCR charges. Aside from technical issues associated with ensuring that fixed charges are appropriate for various commercial and industrial customer segments, it should be kept in mind that the customer base served by SEMCO Gas is 91% residential. Also, from the Company's viewpoint, making the change to a fixed monthly service charge for residential customers will be a significant rate design improvement, and it is unnecessary to apply this rate design methodology to other customer classes at this time.

Q. Why does SEMCO Gas believe that fixed monthly service charges are fair for residential customers?

A. The cost to provide service is essentially the same for all residential customers, irrespective of the volume of gas those customers consume. For example, the cost to prepare and transmit a residential bill does not vary with usage. Similarly,

all residential customers are provided the safety-related services by the Company, such as leak surveys and emergency response to potential leaks on customer premises, and the costs of these services do not vary with usage. The Company generally provides each residential customer with standard-diameter pipe for their main (approximately 87% of new main installed is 2" in diameter), and the same meter and regulator assembly, again without regard to expected usage. The Company's current rate design collects over half of these charges volumetrically, effectively allowing low-usage customers to pay less than their full cost of service.

Q. Explain in more detail why the Company isn't proposing a fixed monthly service charge for commercial and industrial customers?

A. These are relatively small segments of the Company's customer base. Also, commercial and industrial customer groups are not as homogenous as residential customers as a group. The meter, regulator, and service size for commercial and industrial customers vary considerably with the volumes of gas that they consume. There is no standard profile for these customers, in terms of volumes, duration and seasonality of natural gas usage. For example, the profile of gas used to perform the seasonal function of grain drying is different from that of a fast food restaurant's need for space heating, cooking, and hot water. There are numerous other examples of diversity in natural gas requirements in these customer classes, such as a real estate office use versus a superstore, a furniture manufacturer versus a flower shop and so on. The Company's commercial and industrial customers could be categorized into a number of classes based on volumes consumed, and fixed charges could be developed for each of those bands. Additionally, the Company would likely determine that commercial and industrial customer's usage would require review and each customer would have to be put on the appropriate fixed rate on an annual basis. At this time, however, SEMCO Gas believes the variances are substantial

enough to warrant continued volumetric recovery of a portion of the cost to serve these customers.

Q. Does a fixed service monthly charge disadvantage low-income residential customers?

A. No. As Mr. Alger discusses in his testimony, there is compelling evidence that shows that the Company's low-income customers consume gas in the same proportions as the general population of residential customers. In other words, volumetric recovery of a portion of the Company's revenue requirement does not benefit or harm low-income consumers as a group – the effect of using a fixed monthly service charge to collect the Company's base rate revenue is thus the same as that on the general population of residential customers. As mentioned earlier, the cost to serve residential customers is essentially the same, and a fixed monthly service charge eliminates subsidies between different residential customers regardless of socio-economic factors. In truth, most residential customers will not see much of a change in their overall bills, since the fixed monthly charge is a replacement for both the monthly customer charge and the volumetric distribution charge. The small group of high-usage customers should favor this change; it will eliminate what is, in effect, an intra-class subsidy provided to low-usage customers.

Q. Please discuss the impact of a fixed monthly service charge on low usage customers.

A. This group of residential customers might consider themselves to be disadvantaged by a change to a fixed service charge method for recovering the Company's costs of providing service. It is important to remember, however, that the Company's costs of service do not vary with usage, so the relatively few low-consumption customers on the Company's system are only "disadvantaged" by the proposed rate design in the sense that they are not currently paying the full

cost of providing service to them and would lose a subsidy currently being provided by other customers.

Q. What customer response does the Company expect from a changeover to a fixed monthly service charge rate design?

A. Customers are accustomed to fixed charges for other services and have frequently demonstrated a preference for fixed charges. Examples of monthly fixed charge services include: basic local telephone (including access taxes) ($28), mobile telephone ($40), home alarm monitoring services ($33), internet access ($10 to $50), automobile leases ($280), and apartment rent ($450). SEMCO Gas is proposing a $24.09 per month fixed charge (or alternately, a $25.18 fixed charge if LAUF gas costs are included in the Company's base rates), which is comparable in concept to some of the examples given here and on a par with, or substantial below, the fixed charges customers pay for other services. Also, it should be kept in mind that customers are likely to prefer a charge that reduces the amount they will pay during the months when their bills are the highest (i.e., in the winter), rather than a volumetric charge that effectively adds to the highest bills they experience. Given customer acceptance of fixed charges, the Company does not expect a significant negative customer response to the proposed change.

Q. Do you have anything to add on the subject of customer response to the Company's proposed fixed monthly service charge?

A. Yes, I should add that the Company would propose to educate customers about the new rate design, if the Commission were to adopt it. There would be opportunities to do so at the time of approval, in materials included in each residential customer's monthly bill. In addition, the Company's sponsorship of conservation programs would be another natural opportunity to show customers how the new rate design aligns Company and customer interests with respect to conservation.

Also, Mr. Ketchum discusses in his testimony customer responses other utilities have experienced when making rate design changes similar to what the Company is proposing in this filing. In addition, SEMCO Gas has some experience with customer reactions to increased customer charges, when the monthly customer charge in the Battle Creek service territory was increased from $7.00 to $11.00 in April 2005. There were no customer calls pertaining to this increase in the monthly customer charge.

Q. Do SEMCO Gas customers voluntarily participate in a budget bill program?

A. Yes, as of the end of March 2006, 48,275 SEMCO Gas MPSC Division customers participated in budget billing (which is a levelized payment plan for the entire bill for service). This number of customers represents about 20% of all customers in the MPSC Division.

Q. Does the Company believe that this participation in a levelized payment option indicates that customers are receptive to fixed monthly service charges?

A. Yes. As an optional program, budget billing requires customers to make the effort to contact the Company and request to what is, in effect, levelized billing for their entire bill. In my opinion, the fact that about 20% of all customers took it upon themselves to make this choice indicates that customers are not adverse to the concept of fixed monthly service charges.

Q. Does SEMCO Gas believe that a fixed monthly service charge is a disincentive to conservation?

A. No. Even after changing over to a fixed monthly service charge, approximately 80% of the average residential customer bill would still vary with usage and thus provide a sufficient incentive for conservation. (This percentage is calculated using an assumed $9.00/Mcf commodity cost, see example below.) The GCR or commodity portion of the bill is volumetric, and thus this percentage grows in winter months, when residential customers typically consume more gas. As noted, this high percentage portion of the customer bill will continue to rise and

fall with volumetric use, which is generally affected by customer conservation efforts. In my view, having a bill that is 80% (or more in colder months) tied to consumption is such a significant component of the bill that conservation efforts will not be impacted by the comparatively minor percentage change that results from shifting the volumetric recovery of the Company's costs to a fixed monthly service charge, as proposed by the Company. Mr. Ketchum makes the same point in his testimony.

To explain this point further, I should point out that an average residential monthly bill currently consists of about 20% base rate charges and about 80% in GCR or commodity charges. At this time, approximately 10% of the customer bill is collected in a fixed charge – this is the $9.50 monthly customer charge. Another 10% of the average residential bill is collected through the volumetric distribution charge, currently $0.12230 per hundred cubic feet ("Ccf") or about $10.74 per month (based on test year volumes). The change that SEMCO Gas is proposing is to collect the $10.74 and the $9.50 portions of the bill in a fixed monthly service charge. Based on the fully adjusted 2007 cost of service data, the volumetric charge would be $0.17860/Ccf, thus the average monthly charge for the volumetric portion would be $15.68 (based on 2007 adjusted average volumes of 87.786 Ccf/month or 105.3 Mcf/year) the total fixed charge would be the sum of the customer charge and the fixed portion in the volumetric rate or in this case $25.18 (including LAUF gas costs) as explained by Mr. Ketchum. The GCR or gas commodity cost portion of an average residential bill is about $79.00 (using a gas cost of $9.00 per Mcf). The gas commodity represents such a large portion of the bill that, in my view, the price signal and incentive for conservation is preserved even with Commission adoption of SEMCO Gas's proposal for a fixed monthly service charge residential rate design.

Q. Does a fixed monthly service charge guarantee that the Company will earn its authorized rate of return?

A. No. Essentially, what this proposed rate design change does is change the billing determinant used to set residential rates, from volumes sold to number of customers served. As noted, with the sharp decline in use per customer among the Company's customers, the use of volumes as a billing determinant makes it unlikely that the Company will recoup its costs of providing service to customers, including its Commission-authorized rate of return, particularly if a forward-looking sales adjustment is not made to the volumes sold data. In contrast to the volume-based collection of a portion of the Company's costs, use of the number of customers as a billing determinant would give the Company, in my view, a fair opportunity to recoup its costs and earn its authorized rate of return.

Earning that authorized return is not guaranteed, however, should the Commission adopt what I would term the Company's proposed "pro-conservation" rate design. This is because there are other factors that affect the Company's ability to recoup its costs and earn its authorized return. For example, O&M costs that exceed the cost of inflation, such as medical and prescription and pension costs, will affect the Company's financial performance. The state of the economy in Michigan and the associated reduction in SEMCO Gas's customer growth, declining from 5,256 new meters added in 2004 to 4,607 new meters added in 2005, is another risk factor. In fact, a lower growth rate persists, with paid applications for service at 993, 901, and 667, for year-to-date March for 2004, 2005, and 2006, respectively. Although there is minimal customer growth, SEMCO Gas capital expenditures are needed for system improvements, public improvement projects, main relocations, main and service replacements, vehicles and work equipment. Without sufficient customer growth, O&M, and capital cost increases are difficult to offset. As another example, it is clear that regulatory compliance requirements have substantially increased with the passage of the Sarbanes-Oxley Act and the Pipeline Safety Improvement Act, each of which required that the Company take actions that increase its costs.

It appears unlikely to me that regulatory requirements will decrease over time, and unknown compliance requirements pose yet-another risk for SEMCO Gas. Also, as discussed earlier, the cost of gas and gas price volatility have significant impacts on the Company. Dr. Fairchild discusses risk factors that affect the Company in more detail in his testimony.

Q. How does a fixed monthly service charge affect SEMCO Gas's perspective with respect to conservation and energy efficiency?

A. The collection of the Company's revenue requirement from residential customers through a fixed monthly service charge rate design aligns Company and customer interests with respect to conservation and energy efficiency. It is true that SEMCO Gas promotes conservation-related initiatives in spite of the fact that any resulting decline in use per customer adversely affects the Company's ability to recoup its costs of providing service when customer growth fails to offset that declining use. The Company participates in educating customers regarding energy efficiency by (1) publishing information in "Connectivity" (the newsletter that accompanies customer bills) and on the Company's website, (2) purchasing and distributing Department of Energy information on conservation, (3) making public service announcements and giving media interviews in which the Company advises customers to conserve natural gas, (4) sponsoring Michigan's "Save Energy With Ease" program along with other Michigan utilities, and (5) working with large industrial customers to understand the use of natural gas in their processes and provide guidance, where appropriate, on the more efficient use of this fuel.

In sum, given the way in which residential rates are designed to recoup the Company's cost of service currently, doing anything that reduces customer usage disadvantages the Company financially. Despite this disadvantage, the Company takes these actions to encourage conservation because it is the right thing to do.

That said the Company's current rate design, with the volumetric recovery of a significant portion of the fixed costs of providing service, is clearly a disincentive for the Company to promote conservation. An excerpt from the Staff's Report on Energy Efficiency, submitted to the MPSC in January 2006 summarizes this concern well:

> 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.

Aligning the interests of customers and the Company by decoupling consumption from earnings through a fixed monthly service charge removes the financial disincentive for SEMCO Gas to promote conservation. In short, it is easier to "do the right thing" when the financial penalty for doing so is removed.

Q. What more, in terms of encouraging conservation and energy efficiency, will the Company do if this financial disincentive inherent in the Company's current rate design is removed by the Commission?

A. Mr. Lubbers addresses the Company's proposed involvement in a new energy efficiency program and participation in the LIEEF program in his testimony. From my perspective, changing the Company's residential rate design, as proposed, removes a significant financial disincentive to the Company's encouraging conservation and thus allows SEMCO Gas to propose a comprehensive energy conservation program that addresses education, analysis, measurement, tracking and financing without disadvantaging the Company's shareholders. Additionally, the Company is proposing participation in the LIEEF program that promotes conservation as well as provides low-income assistance.

Q. How does a monthly fixed service charge make residential customer bills more understandable?

A. Exhibit A-11, Schedule F-9, "Sample Customer Bills" shows sample bills illustrating the Company's current and proposed rate designs. The Company currently collects its revenues through the monthly customer charge (fixed), the distribution charge (volumetric), and GCR charges (energy charge, and balancing and demand charge, both volumetric). The proposed monthly fixed service charge eliminates the usage-driven distribution charge and, in effect, isolates, in the GCR charges, what the customers are paying for the natural gas they consume. The fixed monthly service charge portion of this bill can then be clearly defined as covering the Company's non-commodity costs of providing service, such as capital investments, maintenance of the meter, pressure regulator, and service pipe, and the costs of preparing and transmitting the bill, and the cost of delivering gas to the customer. As noted earlier, the Company will attempt to educate customers about the new rate design, if it is adopted by the Commission.

To me, as noted earlier in my testimony, this type of design separates the recovery of costs from the usage of the commodity and clarifies the fact that utilities do not make a profit on the gas consumed. The proposed rate design also has the added benefit of reducing revenue collection, and thus reducing customer bills, during the coldest periods, because the Company's fixed costs are recovered on a levelized basis throughout the year.

The concept that gas utilities do not make a profit on the gas they consume continues to be confusing to customers. This confusion is understandable, given that under the current rate structure, the utility collects more revenue to offset its fixed costs when customers use more gas and less revenue to cover its fixed costs when customers use less gas. Structuring rates so that fixed costs are collected in a fixed monthly service charge clearly separates the Company's fixed service costs from the variable costs of service (primarily consisting of the cost of gas) on a customer's bill.

Q. Is a fixed monthly service charge the only method of "decoupling" revenue collection from customer consumption that SEMCO Gas is advocating?

A. Yes, in the sense that this is the rate design that the Company has proposed in this proceeding. While there are many other "decoupling" methodologies, which Mr. Ketchum identifies in his testimony, the Company believes that a fixed monthly service charge is the easiest for customers to understand and accomplishes the same goals more effectively compared to more complex decoupling mechanisms at less cost in information technology, accounting, regulatory auditing, and customer billing requirements.

Q. Why does the Company believe adoption of a fixed monthly service charge rate design would likely reduce the need for future general rate case filings?

A. The Company's current residential rate design relies, in part, on volumetric rate recovery of the Company fixed costs of providing service. Volumetric recovery of the Company's costs is thus dependent upon customer usage. Customer usage, in turn, depends upon the weather and the customer's propensity to conserve gas, either in the choices they make in appliances and home equipment (high efficiency hot water heaters and furnaces) or in their decision to dial-down the thermostat to save on their heating bills. As described earlier in my testimony and in more detail in Mr. Alger's testimony, in the Company's service territory, use per customer is declining substantially, from year to year. What the Company's proposed fixed monthly service charge does is remove customer use from the ratemaking calculus, for residential customers. In my view, collecting the Company's residential revenue requirement in a fixed per customer monthly service charge may make it possible for the Company to hold off filing a rate case that otherwise would be necessary, if the current rate design were kept and use per customer continued to decline substantially. I should point out that this is not just a theoretical consideration; the revenues lost due to the decline in use per customer are a key driver in this rate proceeding.

Q. Please discuss any implementation issues for the Company's proposed fixed monthly service charge for residential customers.

A. If the Commission approves the Company's proposed rate design for residential customers, it is important to note that implementation timing affects the amount of the fixed monthly service charge for the year in which the changeover occurs (from the monthly customer and distribution charges, to the new monthly service charge). The reason that care must be taken in terms of when and how such a change is made is straightforward. Under the Company's current rate design, the Company collects revenues unevenly during the year, with the bulk of its revenues coming in the winter heating season, when customers use more natural gas and thus the Company's distribution charge revenues are higher. Under the proposed residential rate design, the Company would collect its revenues on a levelized basis -- $24.09/month (or alternately, $25.18/month if LAUF gas costs are included) in a January implementation month. With a rate design changeover of the sort proposed in this filing, implementing in any month other than January may increase or decrease the monthly service charge, to match the revenue collection authorized by the Commission.

For example, implementing the $24.09/month service charge (excluding LAUF gas costs) in any month prior to October may result in the Company's recovering more than the revenue requirement authorized by the Commission. Implementing the service charge in October through December may result in the Company's recovering less than the revenue requirement authorized by the Commission. To address this matter, the Company proposes to determine the exact amount of the fixed service charge according to the schedule shown in Exhibit A-11, Schedule F-5-5 of Mr. Alger's testimony.

Q. Would the Company be willing to introduce its proposed fixed monthly service charge rate design on a pilot program basis?

A. Yes, as long as the pilot program was long enough to allow customers to become accustomed to the new bill and otherwise begin to see the benefits of aligning Company and customer interests with respect to conservation. The Company proposes that the Commission institute the new fixed monthly service charge rate design for a five-year period, if the MPSC wishes to conduct a pilot program. The Company also would be willing to report to the Commission periodically during this five-year period on its experience with the new rate design.

Q. If a portion of the Company's revenue requirement were to be collected volumetrically, what volumetric use per customer would SEMCO Gas propose?

A. As I have explained above, the Company believes that fixed costs should be collected in fixed charges, and a fixed monthly service charge is the appropriate rate design for the Company's residential customers. If the Commission does not approve the fixed monthly service charge as proposed, however, and some portion of the Company's base rates were to be collected volumetrically, SEMCO Gas proposes setting residential rates based on use per customer of 95.4 Mcf/year.

Q. Please discuss the decline in use per customer and explain the proposed use per customer figure of 95.4 Mcf/year for volumetric rate recovery.

A. Throughout my testimony, I refer to the sharp decline in use per customer. To be specific, in the Company's 2004 general rate case filing, use per residential customer averaged 113.6 Mcf/year in test year 2005. In this general rate case filing, use per residential customer averaged 105.4 Mcf/year for fully adjusted test year 2005. The Company expects use per customer in 2006 and 2007 to average about 95.4 Mcf/year. Mr. Alger explains the basis for this expectation in more detail in his testimony.

In essence, the 95.4 Mcf/year use per customer figure is based upon the Company's actual results for January through March of 2006, normalized using 15-year weather data. First quarter 2006 actual results (weather-normalized)

reflect among other things, the customer response to higher gas prices and frequent public messages urging customers to conserve natural gas.

Q. Please continue your discussion of this topic.

A. Using a residential use per customer figure as a billing determinant for volumetric rate recovery that is higher than the 95.4 Mcf/year proposed by the Company if its rate design proposal is rejected will effectively put the Company in the position of chasing customer use as it declines. To me, this would result in a revenue shortfall and the Company not recouping its costs of providing service, including a reasonable return on investment. To follow this logic further, use of a billing determinant higher than 95.4 Mcf/year would likely necessitate further rate case filings and the related time and expense associated with them. Mr. Alger's Exhibit A-11, Schedule F-5-1, "Declining Use Per Customer – 30 Year Norm" clearly shows the trend of declining use per customer since 1996, when test year 1997 anticipated that customers would use 123.1 Mcf/year on average. The first few months of 2006 show an even steeper decline in the use per customer than in the previous ten-year period.

In my view, this trend makes it clear that simply determining the Company's volumetric distribution rate by projecting historic year volumes to the test year by adding customer growth and basing use per customer calculations on 30-year normal weather, as has been done in the past, will result in a revenue shortfall for the Company. In contrast, adoption of the Company's proposed fixed monthly service charge rate design would make it unnecessary to deal with these issues, because the billing determinants for the Company's rates would no longer be weather-normalized estimates of use per customer during the rate effective period.

Q. If the fixed service charge is not approved by the Commission, what would the Company's position be on its proposed conservation program and LIEFF participation?

A. As previously mentioned, volumetric rate recovery is a financial disincentive to utilities with respect to conservation. When a portion of revenues are to be collected via volumetric use, promoting conservation, as a mathematical certainty, harms the Company's ability to recoup its costs of providing service, including a fair return on its investment. Unless there were some other way in which to align Company and customer interests with respect to conservation, rejection of the Company's proposed fixed monthly service charge rate design would make it inappropriate for the Commission to require the Company to implement its conservation and LIEEF proposals. In his testimony, Mr. Ketchum discusses some of the problems encountered in the past in attempting to align utility and customer interests with respect to conservation, including the complexities of attempting to quantify lost sales due to demand-side management programs.

Rate Design – Lost and Unaccounted for Gas Costs

Q. What rate design is SEMCO Gas proposing for recovering LAUF gas costs?

A. Under the Company's current rate design, LAUF gas costs are recovered in base rates, using what I will term a five-year average methodology. What this means is that the amount included in the Company's base rates for LAUF is calculated by averaging the percent of gas lost for each of the past five years, then applying a test year cost of gas (see Mr. Alger's Exhibit A-8, Schedule B-10). The Company is proposing that LAUF gas costs be removed from base rates, and instead be reviewed and recovered through the GCR process, as one of the components of the cost of gas.

Mr. Dubay defines LAUF gas costs and how the Company manages and accounts for these gas costs in his testimony. Mr. Alger shows the calculation for removing LAUF gas costs from base rates in his testimony (See Exhibit A-9, Schedule C-5).

Q. Why, in your opinion, should LAUF gas costs be collected in the GCR process?

A. LAUF gas costs relate directly to the cost of gas and should be (1) collected as part of the GCR or commodity cost charged to customers, and (2) reviewed annually as part of the GCR reconciliation process. The cost of the molecules of gas are lost in the delivery process are actual costs incurred by the Company and the GCR portion of customer bills should permit recovery to reflect this physical reality. These volumes are removed from the GCR process under the MPSC's current ratemaking approach and addressed in base rates in a process that, by definition, never allows the Company to recover its actual LAUF gas costs.

I should add that LAUF gas costs are treated as a component of gas costs in the majority of jurisdictions in the U. S., as discussed in Mr. Ketchum's testimony.

Q. Please continue.

A. Currently, a five-year average is calculated for LAUF gas and a dollar amount is included in base rates to compensate the Company for its LAUF gas costs. This amount is not adjusted until the next base rate case, even if the underlying cost of gas increases or decreases substantially. My understanding is that the rationale behind this rate recovery method is that regulatory lag (i.e., the time it takes to change base rates to reflect current cost data, which is further lengthened under the MPSC's current ratemaking convention, through use of a five-year average instead of adjusted historic test year data) is that it provides an incentive for gas utilities to minimize LAUF gas. The theory is that; if the amount of LAUF gas is reduced by actions taken by the utility year after year, and a higher volume was used to set base rates, a utility reaps a reward, because it collects more for LAUF gas costs than it actually experiences over time.

Q. Discuss this incentive, from the Company's perspective.

A. SEMCO Gas is not motivated by this ratemaking incentive to control LAUF gas volumes. The Company effectively manages LAUF gas as a part of its commitment to safety – natural gas leaks, which are a primary component of

LAUF, create hazards for Company personnel, customers, and the public, and the Company attempts to identify and reduce system leaks to minimize those hazards. Indeed, this is a primary reason why SEMCO Gas's LAUF gas volumes, as a percentage of system throughput, are low when benchmarked against other local distribution companies. As discussed in Mr. Dubay's testimony, the Company's percent of LAUF gas (at 0.59% in 2003, 0.97% in 2004 and 0.95% in 2005) compares favorably to the most recent data reported by the American Gas Association (1.23% average LAUF gas in 2003).

Q. Please discuss the cost associated with LAUF gas volumes.

A. When LAUF is managed well, as is the case at SEMCO Gas, the key variable that determines the Company's LAUF gas costs is the price of gas, including price volatility. If natural gas prices increase substantially, the Company's allowance for LAUF gas costs in base rates does not match the expense actually incurred by the Company, by a substantial amount. The result, in this scenario, is that the Company never recovers a legitimate cost of providing service to customers. It is important to point out, in this regard, that, while the Company has some control of the amount of LAUF gas, the Company has no significant degree of control over the market price for natural gas. In fact, however, under the Commission's current ratemaking convention for LAUF gas costs, the Company is held financially responsible for the effects of market price changes.

Let me provide an example from 2005. In the Company's 2004 general rate case, the requested allowance for LAUF gas costs was $3,077,860, using estimated LAUF gas volumes of 431,073 Mcf and a price of $7.14/Mcf. During 2005, LAUF gas volumes were 407,105 Mcf. On the price side of the equation, however, the price applied to LAUF gas volumes during 2005 averaged $8.4869/Mcf, with the result that the difference between the amount requested in base rates for LAUF costs and the Company's actual experience of $3,455,063, was $377,203. This amount takes on added significance when it is compared to

the Company's 2005 MPSC Division earnings of $9.3 million. The change in LAUF gas costs in this period were 4.1% of 2005 MPSC Division earnings. Even with such a significant impact on earnings, the Company is simply unable to file for and receive timely rate relief for this cost item, largely because the market price changes that caused the LAUF gas costs to increase so substantially cannot be predicted with any precision and because of the time it takes for the Company to prepare and the Commission to process a general rate case filing.

Q What, from your viewpoint, are the advantages of including LAUF gas costs in the GCR, as part of the cost of gas?

A. From my perspective, a more equitable solution that recognizes the realities of the situation (namely, that the current ratemaking treatment of this item neither (1) creates an incentive that truly motivates the Company's behavior, nor (2) gives the Company a fair opportunity to recoup an important cost of service item) is an annual process that matches the recovery to the expense, in terms of both LAUF gas volumes and price, with an annual opportunity for the Commission to conduct a prudence review of the Company's efforts to control LAUF gas volumes. Such an annual process already exists in the form of the annual GCR plan and reconciliation filings.

Q. Please discuss the matching of LAUF gas cost recovery and expense.

A. In my view, it makes sense to match the recovery of LAUF gas costs to the expense actually incurred by the Company. As noted above, the incentive that was apparently intended to be a product of the current ratemaking treatment of this item is ineffective. The truth of the matter, moreover, is that the driver of LAUF gas costs is the market price of natural gas. The Company does not believe that it is appropriate, in such a circumstance, for shareholders to profit – and customers to "overpay" for this expense – when the market price for natural gas is below the price that was assumed in setting base rates. By the same token, the Company should not lose financially, as happened in 2005, when the

market price for natural gas exceeds the price that was assumed in setting base rates.

Q. Please discuss the procedural aspects of the Company's proposal.

A. The reason for recommending that the existing GCR process be used to address LAUF costs is efficiency. The GCR process simply is an appropriate proceeding for the Commission to examine the Company's prudence with respect to LAUF gas costs, since prudence is the main subject of GCR reconciliation proceedings. Similarly, by definition, the GCR rates approved by the Commission in such a proceeding are the proper rate at which to compensate the Company for the LAUF gas costs that results from delivering natural gas to customers.

Q. Does collecting LAUF gas costs through the GCR process mean that LAUF percentages will rise?

A. No. The Company has no incentive to allow the percentage of LAUF gas to increase or to become less vigilant in reducing LAUF gas. This is because, as I noted earlier, natural gas leaks are a potential source of harm and liability and are monitored closely and addressed promptly because of those risks. If the Commission had any doubt about the Company actions to control LAUF gas volumes, those actions would be subject to a prudence review in the GCR process.

Q. Is SEMCO Gas proposing an alternative to collecting LAUF through the GCR process?

A. The Company believes that LAUF gas is a cost of gas item. Natural gas cannot be purchased and delivered without there being some discrepancy between the volumes purchased and sold. As noted, when managed well, LAUF gas costs vary because of changes in the underlying market price of the gas. A process is already in place for planning, reconciling, and reviewing gas cost recoveries, and most jurisdictions address LAUF gas issues as part of the gas cost review process.

However, if the Commission does not approve the collection of LAUF gas costs through the GCR mechanism, the Company requests Commission approval of an annual true-up for LAUF gas costs. Such an annual true-up is necessary to give the Company a fair opportunity to recover this cost of serving customers, given the fact that the market price for natural gas has been substantially higher than was used to set the Company's base rates and how much a change in this one expense item can affect the Company financially.

Q. How would an annual true-up mechanism for LAUF gas costs work?

A. In an annual filing, the Company would compare actual LAUF gas costs and the recovery of those costs in base rates (reflecting the LAUF gas costs revenue amount determined in this case). Any under-recovery of expenses would be surcharged to customers, and any over-recovery of expenses would be refunded to customers, subject to review by the MPSC and any parties choosing to intervene in the proceeding. The Company would propose that the schedule for such a filing coincide with the GCR reconciliation case and would request that the LAUF true-up proceeding be combined with the Company's annual GCR reconciliation case, for the purpose of efficiency. The methodology for this annual true-up is discussed in more detail in Mr. Alger's testimony.

Q. Are you aware of situations where similar costs are recouped as proposed by the Company?

A. Mr. Ketchum provides information on how these costs are treated in other jurisdictions. In addition, I am aware that electric utilities in Michigan are able to recover, in their annual proceedings, increases in the unit price of lost kilowatt-hours. Therefore, I believe the Commission should, at a minimum, allow the Company to recover in its annual gas proceedings, increases in the unit price of lost gas. If losses of kilowatt-hours are power supply costs under the PSCR clause, then losses of Mcf are gas supply costs under the GCR clause.

Rate Design – Uncollectible Expense

Q. Is the Company proposing a change in the recovery of uncollectible expense?

A. Yes. SEMCO Gas is proposing an annual true-up for the uncollectible expense.

Q. Define uncollectible expense.

A. According to information provided to me by Mr. Warsinske, who also is a witness in this proceeding, FERC Account 904, Uncollectible Accounts, states "This account shall be charged with amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits shall be made to Account 144, Accumulated provision for uncollectible accounts – Cr. Losses from uncollectible accounts shall be charged to Account 144." This is the technical definition. To me, in a more generic sense, Uncollectible expense is the cost associated with the failure of some customers to pay their bills for service, in full or at all.

Q. Why is the Company proposing this change in the ratemaking treatment of Uncollectible expense?

A. The Company manages the uncollectible process well, though that process is affected by rules imposed by the Commission on the state's utilities. In 2005, a reduction in Uncollectible expense as a percentage of sales was achieved, when compared to 2004, from 0.44% to 0.41%, in spite of difficult economic times in Michigan and the effect of increased gas costs on the ability of customers to pay their bills for natural gas service.

Q. You just described uncollectible expense as a percentage of sales. Please discuss the dollars associated with this expense item.

A. Even though, on a percentage of sales basis, the Company's Uncollectible expense was reduced in 2005, as previously discussed, the Company's Uncollectible expense increased by over $178,000 in 2005 to $1,587,080, when compared to the Company's 2004 Uncollectible expense of $1,408,793. The reason for this increase is the market price of gas. When gas prices increase significantly and gas costs comprise about 80% of the average residential customer bill, customers typically have more difficulty in paying their bills for

service – and the Company's Uncollectible expense increases, again largely because of the increase in the market price of gas. The Company has no control over the market price for natural gas, yet once again is held financially responsible, from a ratemaking perspective, for the effects that the market price increase engenders.

Q. How would the proposed annual true-up mechanism work?

A. In an annual filing, the Company would compare its actual Uncollectible expense to the amount it recovers in base rates for that expense item (reflecting the uncollectible revenue amount determined in this case). Any under-recovery of this expense would be surcharged to customers, and any over-recovery of this expense would be refunded to customers, subject to review by the MPSC and any parties choosing to intervene in the proceeding. The methodology for this annual true-up is discussed in more detail in Mr. Alger's testimony.

Q. Please discuss the impact of MPSC rules on the Company's Uncollectible expense, including whether that is another reason for an annual true-up mechanism.

A. As noted, the Company does not determine unilaterally whether and when a customer's natural gas service can be disconnected for non-payment. This means that the Company also does not control its Uncollectible expense percentage, in the sense of being able to terminate service to any customer for non-payment. In fact, MPSC rules govern the termination of service to customers. In 2005, for example, in Case No, U-14668, the Commission found that emergency rules should be promulgated. These rules changed (1) the terms of the Winter Protection Program, extending the "no shut-off" period to include November 1, 2005 to March 31, 2006, (2) the due date for utility service bills to not less than 22 calendar days from the date the bill was sent to the customer, (3) shut-off rules for customers who receive estimated bills, (4) shut-off rules for customers 65 years of age or older and those with household income not

exceeding 200% of the poverty level, and the calculated monthly amount to continue service to 6% of the customer's estimated annual bill, and (5) required that monthly payments for customers pursuant to a settlement agreement not exceed $50, plus the amount of the customer's monthly natural gas bill.

For SEMCO Gas, these changes in MPSC emergency rules played a large part in increasing all arrears by $4,230,605, when comparing data as of March 31, 2006, to data as of March 31, 2005. These new rules were not in effect when the Company's base rates were last set by the MPSC. Mr. Forsyth addresses the impact of billing rule changes in detail in his testimony.

I should add, at this point, that SEMCO Gas believes that the MPSC has a duty to respond to emergency conditions, such as the Commission determined existed in 2005. It is incumbent upon the Commission, however, when it requires utilities to implement significant changes to rules in a relatively short time frame, to allow utilities to recover the expense of implementing those rules in a comparably short time frame. An annual true-up proceeding allows a utility to adjust, in a timely manner, to the significant changes in Uncollectible expenses occasioned by billing rule amendments and the volatility of natural gas prices. Mr. Forsyth addresses the impact of the billing rule changes that are anticipated and how they are expected to impact SEMCO Gas in his testimony.

From the perspective of the Company, the influence of Commission rules on the Company's Uncollectible expense experience is another reason for an annual true-up of this expense item. That way, the impact of MPSC rule changes affecting Uncollectible expense will be reflected promptly in amounts charged to customers. Without such a true-up, an MPSC rule change would have the effect of impairing the Company's ability to recoup its costs of providing service. Requiring a utility to file a base rate case to update an expense item that, in effect, was changed by Commission action is, in my view, setting up an inappropriate regulatory hurdle under the circumstances I have described. Mr.

Ketchum addresses the adoption of true-up mechanisms in other jurisdictions in his testimony.

Energy Efficiency Program Participation

Q. Is SEMCO Gas proposing a conservation and energy efficiency program?

A. Yes. The Company is proposing a customer efficiency and conservation program called "This Cold House." The program addresses energy conservation in a comprehensive manner, by focusing on education, analysis, measurement, tracking and financing. The program ranges from weatherization, energy audits, help in purchasing energy efficient appliances, and partnering with Michigan experts in the energy conservation field. The program is discussed in detail in the testimony of Mr. Lubbers.

Q. Which customer classes may participate in the program?

A. There are several energy efficiency proposals included in the plan for residential customers. Mr. Lubbers addresses the reasons for offering conservation assistance to residential customers, and not to all customer classes, in his testimony.

Q. Does SEMCO Gas intend to perform efficiency improvements and energy audits for its customers?

A. No. The Company believes it is best to "partner" with experts in energy efficiency to provide program benefits to customers. Energy efficiency vendors are better equipped to perform audits, install improved equipment, and perform other energy saving measures than SEMCO Gas is. To the extent practicable, the Company intends to maximize the use of Michigan-based contractors. This should provide a double benefit to the Michigan economy – customers will benefit from reduced energy costs, and reliance on Michigan-based contractors should create jobs in the state.

Q. Please discuss SEMCO Gas's efficiency program with regard to the Staff Report on Energy Efficiency provided to the Commissioners on January 31, 2006.

A. The Staff's report recommends that offering an energy efficiency program be a condition for including fixed charges in a utility's rate design. In this rate filing, the Company is proposing its comprehensive energy program "This Cold House" and to participate in LIEEF funding, which also has an energy efficiency component. The Company views these programs as sufficient to meet the Staff's test of offering an energy efficiency program as a condition for including fixed charges in rate design.

Q. Does SEMCO Gas believe that Commission adoption of its proposed fixed monthly service charge should be dependent in some way upon the Company's involvement in conservation and energy efficiency programs?

A. As a technical matter, no. Notwithstanding the proposed energy efficiency programs, SEMCO Gas believes that properly aligned rates should be put in place for the reasons explained elsewhere in my testimony and this filing, including eliminating the Company's financial disincentive to promote conservation, reflect sound economic principles, and make rates more understandable. Approval of a properly aligned rate design should not be predicated on the size or effectiveness of utility-sponsored energy efficiency programs.

ENERGY EFFICIENCY PROGRAM AND LIEEF FUNDING

Q. Please describe the Company's proposal for funding its participation in the "This Cold House" and LIEEF programs.

A. The Company's relatively small size and financial condition are the primary reasons for proposing a different funding mechanism for its participation in these programs, instead of the cost recovery that would occur under traditional ratemaking principles. The Company proposes to establish a fund in which to collect a surcharge for the amount authorized in this rate case to be expended on conservation and for LIEEF participation. The surcharge is proposed to begin on the day following the MPSC order in this case and to be collected annually in

equal monthly amounts. "This Cold House" is designed as a menu of options from which conservation measures may be chosen to the extent that the Commission approves funding for the program. An annual report will be filed with the MPSC to adjust the surcharge to reflect actual program costs. Any balance in the fund remaining at the end of a year will fund conservation efforts in the following year. The Company plans to fully expend the dollars collected in the fund for conservation efforts and expects any balance in the fund to be negligible. If, however, there were a balance in the fund and the program was terminated or suspended, the Company would refund that balance to customers, subject to Commission approval.

Mr. Lubbers describes the "This Cold House" program and the menu of conservation options and their costs, as well as the details on the Company's proposed participation in LIEEF, in his testimony.

Q. What input does the Company need from the Commission with respect to the Company's proposed "This Cold House" program and LIEEF participation.

A. From the Company's perspective, the amount that the Commission allows the Company to collect to fund these programs will determine the extent of the "This Cold House" program and LIEEF participation. If, however, the Commission would prefer that the Company undertake specific efficiency and conservation initiatives with amounts collected from customers, it would be helpful to have that input.

Main and Compressor Replacement Program

Q. Please describe the Company's proposed accelerated main and compressor replacement program.

A. The Company is proposing a program to support the accelerated replacement of unprotected and bare steel mains in service in the SEMCO Gas system. The program also covers certain compressor replacements, for compressors housed in two compressor stations located in service territory regulated by the MPSC

(known as the "MPSC Division"). As described in detail in Mr. Larsen's testimony, the 15-year program proposed by the Company is intended to speed up the replacement of about 240 miles of pipe and 5 compressors. The program is intended to add to the miles of unprotected steel pipe that are routinely replaced by the Company each year in conjunction with public improvement projects. The compressors identified for replacement have been in service for many years and incur a great deal of wear under the frequent "stop and start" injection cycles utilized by the Company to meet daily balancing and system supply requirements.

Q. Please describe the ratemaking proposal for this program.

A. The Company is proposing that the capital-related costs (including return on investment, depreciation expense and property taxes) for the annual $5 million investment in unprotected and bare steel and compressor replacements be surcharged to the Company's customers as a net amount with the surcharge or credits for Uncollectible expense and for LAUF gas costs, if LAUF gas costs are to be collected as an annual true-up in base rates. The first year of the program (2007) is proposed to be included in base rates as a known and measurable adjustment; with years following 2007 added as incremental surcharges. When subsequent rate cases are filed, and the Accelerated Replacement Program ("ARP") capital investments are included in rate base, the portion of the surcharge associated with the capital-related costs of those capital investments will cease. Mr. Larsen explains how the surcharge is calculated and administered throughout the ARP in his testimony.

Mr. Dubay discusses why the Company is requesting Commission approval of the ARP, Dr. Fairchild discusses the capital-related costs for the program in his testimony, and Mr. Alger discusses the annual surcharge mechanism in his testimony. Additionally, Mr. Ketchum describes the reasons

why the Commission should give favorable consideration to this ratemaking proposal and the ARP program.

Q. The Company has proposed several true-up mechanisms. Does the Company propose that each true-up be shown separately on customer bills?

A. No. In the interest of simplicity, SEMCO Gas proposes to net the surcharges and credits associated with the proposed Uncollectible expense, conservation, and ARP true-ups. Additionally, if the LAUF gas costs remain in base rates, the incremental amount for the Company's proposed "true-up" for this item would be included in this line item.

Environmental Expenditures

Q. Please discuss SEMCO Gas's environmental expenditures.

A. The manufactured gas plant ("MGP") and other environmental expenses incurred by SEMCO Gas's MPSC Division from August 2004 through March 2006, the expected costs for April 2006 through December 2007, the associated regulatory rationale for the expenses, and the prudence of the expenditures are addressed in this section of my testimony.

Q. Please explain Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)".

A. This exhibit details, in part, the actual environmental expenditures made to investigate and do other work in connection with former MGP sites and other environmentally-related matters for SEMCO Gas's MPSC Division for the time period September 2004 through March 2006. These costs are collected in Account 186, miscellaneous deferred debits. These deferred accounts are numbered sequentially and reflect the year in which the expenses were incurred. The total amount expended for environmental-related work for the time period September 2004 through March 2006 in the deferred sub-accounts is $564,488. The amount in each sub-account is amortized over a ten-year period in

accordance with the MPSC's November 7, 1997 order approving such accounting in MPSC Case No. U-11409.

This exhibit also shows the expected costs for April 2006 through December 2007 totaling $995,018. I will discuss the work associated with these costs and the reasons for including them as known and measurable changes to historic test year data later in this section of my testimony.

Q. Why is SEMCO Gas investigating environmental conditions at the MGP sites?

A. The Company is subject to local, state and federal laws and regulations that require, among other things, the investigation and, if necessary, the remediation of contamination associated with these sites, irrespective of fault, legality of initial activity, or ownership, and which may impose liability for damages to natural resources. The Company has complied with the applicable Michigan Department of Environmental Quality ("MDEQ") requirements, which require current landowners to mitigate unacceptable risks to human health from the byproducts of manufactured gas plant operations and to notify the MDEQ and adjacent property owners of potential contaminant migration. The Company is currently investigating these sites, and anticipates conducting any necessary additional investigatory and remedial activities as appropriate.

Q. What environmental expenditures in Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)" were incurred in order to meet compliance requirements?

A. The environmental investigation costs listed in Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)" were expenses incurred in fulfilling compliance requirements associated with Section 20107a of Part 201, the Michigan Natural Resources and Environmental Protection Act ("NREPA"), which specifically requires that owners and operators exercise due care to ensure that existing contamination on a property does not cause unacceptable risks and is not exacerbated. Such measures include evaluating the

contamination and taking necessary response actions. Due care requirements are not related to the owner's or operator's liability for investigation and remediation of the contaminants; they apply to non-liable parties and liable parties alike. Section 20107a of NREPA requires that an owner or operator of a facility do all of the following with respect to hazardous substances at a facility: prevent exacerbation of the existing contamination; prevent unacceptable human exposure and mitigate fire and explosion hazard to allow for the intended use of the facility in a manner that protects the public health and safety; take reasonable precautions against the reasonably foreseeable acts or omissions of third parties; and notify the MDEQ and others.

Q. What other expenses are summarized in Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)"?

A. Additional expenses listed in Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)" reflect fees associated with an initiative to pursue insurance recovery from insurance carriers and contributions from other potentially responsible parties to offset the Company's MGP expenditures. This process involves obtaining and reviewing insurance policies and developing all the potential claims against insurance carriers that provided coverage to the Company and its corporate predecessors. This process is sometimes referred to as "insurance archeology," to denote how intensive and detailed the work is. This process also involves the review of property records, purchase and sale contracts, and corporate histories to determine if there are any additional persons who are or may be legally obliged to contribute to the investigation and remediation costs for the relevant sites.

Q. What is the current status of the initiative?

A. The initiative dollars expended from August 2004 through March 2006 reflect outside consultant research required to determine whether there was insurance coverage for each MGP site or whether other potentially responsible parties

shared liability for investigatory and remediation costs. Preliminary contact has been made with insurers and various potentially responsible parties to review initial baseline findings and initiate discussions on sharing investigatory and remediation costs at the appropriate sites.

Q. Why is the Company pursuing recovery of insurance dollars and contributions from potentially responsible parties for the MGP sites?

A. The Company continues to incur environmental investigation and remediation costs for these sites. In an attempt to minimize the potential financial impact on the Company and customers from these activities, an initiative was begun in 2003 to identify insurers that may have provided coverage for environmental conditions and other potentially responsible parties who might be obliged to fund investigatory and remedial work, in order to defray the Company's expected environmental investigatory and remediation expenses.

Q. Has the Company recouped any dollar amounts for pollution claims through settlements with insurers or others?

A. Not at this time. As stated earlier, this initiative was begun in 2003 and has involved significant preliminary investigation of the ownership of these sites and insurance coverage purchased by the Company and its corporate predecessors in the past. The Company is in the first stages of contacting insurance carriers that provided coverage for the sites being investigated and pursuing other potentially responsible parties. In similar cases with other utilities, the timeframe from start to finish for similar initiatives has been anywhere from two to six years, and in some cases longer if any extensive litigation is involved. This initiative will continue for the foreseeable future and may require the Company to institute litigation.

Q. Are the expenditures listed on Exhibit A-8, Schedule B-6, "Environmental Expenditures (Including MGP's)" reasonable and prudent?

A. In my opinion, yes. The costs summarized on this exhibit listing the environmental expenditures were made in order to meet existing regulatory compliance requirements and to seek out and, where applicable, to obtain participation in the investigation and remediation costs of these environmental sites by third parties. While the outcome of these efforts is uncertain, these efforts are necessary steps in addressing the investigation and remediation of these sites in a systematic, cost-effective way.

Q. Please discuss the planned environmental expenditures for April 2006 through December 2007.

A. The Company has developed comprehensive work plans for the former Albion and Marysville MGP sites to characterize source areas, define the extent of facilities, evaluate ground water-surface water interfaces and other pathways, perform due care evaluations, and prepare what are known as "Remedial Action Plans" for submission to the MDEQ. These activities are scheduled, planned, and budgeted through the end of 2007. Contractors will be conducting the field investigations and coordination, providing environmental reports (including environmental due care reports), and managing these projects under the direction of the Company's environmental engineer. The detailed work plan for these activities support April through December 2006 expenditures of $508,923, and 2007 expenditures of $486,095, for a total of $995,018 in known and measurable expenditures. This is in addition to the actual dollars spent from August 2004 to March 2006 on environmental activities.

SEMCO Gas is committed to following this work plan and believes that these known and measurable changes should be taken into account in setting the revenue requirement in this proceeding.

Witnesses

Q. Please identify the witnesses testifying in this case and briefly summarize the areas addressed by each witness.

A. I have already mentioned many of these witnesses in my testimony and provided some information about the topics they will address. The following witnesses are filing testimony and exhibits in support of the Company's filing:

Eugene N. Dubay is the Company's chief policy witness and is sponsoring testimony that provides an overview as to the Company's financial situation and the events and circumstances that necessitate this filing.

Bruce H. Fairchild is sponsoring testimony and exhibits addressing a number of the schedules required by the Commission's standardized rate case filing requirement and developing SEMCO Gas's requested rate of return.

John R. Alger is sponsoring testimony and exhibits to address 2005 historic year customers and volumes, the decline in use per customer, weather normalization, sales and transport adjustments, LAUF and Company use gas, storage cost increases on working capital and advertising and contributions, as well as the details of how certain proposed ratemaking mechanisms would work.

Malcolm R. Ketchum is sponsoring testimony on elements of the Company's proposed rate design, typically including a national perspective on those proposals, including fixed cost recovery, methodologies for collecting LAUF gas costs and Uncollectible expense, and weather normalization.

Steven W. Warsinske is sponsoring testimony and exhibits that develop parts of the revenue deficiency for the historical 2005 and projected 2007 test years.

Rick L. Ayers is sponsoring testimony and exhibits on new technology initiatives.

Daniel J. Forsyth is sponsoring testimony and exhibits on the impact to SEMCO Gas of the pending changes in customer billing rules.

James C. Larsen is sponsoring testimony on the Company's proposed main and compressor replacement program and non-revenue producing plant.

Timothy J. Lubbers is sponsoring testimony on SEMCO Gas's conservation and LIEEF participation proposal.

James A. Van Sickle is sponsoring testimony and exhibits on proposed tariff changes.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
_____	)	

DIRECT TESTIMONY AND EXHIBIT OF BRUCE H. FAIRCHILD

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Bruce H. Fairchild
On Behalf of
SEMCO Energy Gas Company

I. INTRODUCTION

Q. Please state your name and business address.

A. Bruce H. Fairchild, 3907 Red River, Austin, Texas 78751.

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

A. I am a principal in Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

A. Qualifications

Q. Describe your educational background, professional qualifications, and prior experience.

A. I hold a BBA degree from Southern Methodist University and MBA and PhD degrees from the University of Texas at Austin. I am also a Certified Public Accountant. My previous employment includes working in the Controller's Department at Sears, Roebuck and Company and serving as Assistant Director of Economic Research at the Public Utility Commission ("PUC") of Texas. I have also been on the business school faculties at the University of Colorado at Boulder and the University of Texas at Austin where I taught undergraduate and graduate courses in finance and accounting.

Q. Briefly describe your experience in utility-related matters.

A. While at the Texas PUC, I assisted in managing a division comprised of approximately twenty-five professionals responsible for financial analysis, cost allocation and rate design, economic and financial re-

search, and data processing systems. I testified on behalf of the PUC staff in numerous cases involving most major investor-owned and co-operative electric, telephone, and water/sewer utilities in the state regarding a variety of financial, accounting, and economic issues. Since forming FINCAP in 1979, I have participated in a wide range of analytical assignments involving utility-related matters on behalf of utilities, industrial consumers, municipalities, and regulatory commissions. I have also prepared and presented expert witness testimony before a number of regulatory authorities addressing revenue requirements, cost allocation, and rate design issues in the areas of gas, electric, telephone, and water/sewer. I have been a frequent speaker at regulatory conferences and seminars and have published research concerning various regulatory issues. A resume that contains the details of my experience and qualifications is attached as Attachment A, with Attachment B listing my prior testimony before regulatory agencies since leaving the Texas PUC.

B. Overview

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor a number of the schedules for the rate filing being submitted by SEMCO Energy Gas Company ("SEMCO Gas") with the Michigan Public Service Commission (the "MPSC" or "Commission"). In addition, I will sponsor several adjustments to rate base and operating expenses, recommend a rate of re-

turn on rate base, and develop a capital carrying cost for use in SEMCO Gas's proposed Accelerated Replacement Program ("ARP").

Q. Please summarize the basis of your knowledge and conclusions concerning the issues on which you are testifying in this case.

A. In preparing my analyses and testimony in this case, I utilized a variety of sources of information that would normally be relied upon by a person in my capacity. I am generally knowledgeable about the natural gas industry from my prior work with many of the major gas distribution and transmission companies in the Southwest and elsewhere in the U.S. I am generally familiar with the organization, finances, and operations of SEMCO Energy from my participation in SEMCO Gas's last two rate cases before the Commission (Case Nos. U-13575 and U-14338) and previous work with SEMCO Energy's Alaska division ("ENSTAR"). In connection with the present filing, I reviewed a variety of accounting and financial data relating to SEMCO Gas and SEMCO Energy, and had extensive conversations with management in the course of preparing the present rate case filing. In addition, I examined information regarding capital markets generally and investor perceptions, requirements, and expectations for gas utilities specifically. These sources, coupled with my experience in the fields of finance, accounting, economics, and utility regulation, enabled me to acquire a working knowledge of SEMCO Gas and formed the basis for my conclusions.

Q. What time periods served as the bases for SEMCO Gas's rate filing?

A. Section A of this filing is based on historical experience for the year ended December 31, 2005, with Section B being predicated on a 2007 test year.

II. SECTION A

Q. Please describe Section A of SEMCO Gas's filing.

A. Section A reflects the results of SEMCO Gas's Michigan utility operations (excluding its Battle Creek division) for the twelve months ended December 31, 2005 using the Commission's standardized filing requirements. All of the information in this portion of the filing is prior to adjustments to normalize data, eliminate non-recurring items, account for known and measurable changes, and reflect other regulatory conventions. Accordingly, while Section A provides historical data that serves as the starting point for establishing rates, SEMCO Gas's proposed rates are ultimately based on the data and information contained in Section B of the rate filing.

Q. Which schedules in Section A of SEMCO Gas's filing are you sponsoring?

A. I am sponsoring the following schedules in Section A, all of which were prepared by me from SEMCO Gas's books and records:

Exhibit	Schedule	Title
Exhibit A-1	Schedule A-1	Computation of Gas Revenue Deficiency for Year Ended December 31, 2005
	Schedule A-2	Computation of Revenue Multiplier for Year Ended December 31, 2005

	Schedule A-3	Comparative Earnings Schedule
Exhibit A-2	Schedule B-1	Average Rate Base and Capital for Year Ended December 31, 2005
	Schedule B-2	Rate Base – Average Net Plant for Year Ended December 31, 2005
	Schedule B-3	Rate Base – Balance Sheet Working Capital 13-Month Average for Year Ended December 31, 2005
Exhibit A-3	Schedule C-1	Adjusted Net Operating Income for Year Ended December 31, 2005
	Schedule C-2	Recorded Net Income for Year Ended December 31, 2005
	Schedule C-3	Adjusted Net Operating Income-Income Tax Savings for Year Ended December 31, 2005
	Schedule C-4	Tax Effect of Interest Synchronization Adjustment for Year Ended December 31, 2005
Exhibit A-4	Schedule D-1	Overall Rate of Return Summary for Year Ended December 31, 2005
	Schedule D-2	Long-term Debt Cost for Year Ended December 31, 2005
	Schedule D-3	Cost of Short-term Debt for Year Ended December 31, 2005
	Schedule D-4	Preferred Stock Cost for Year Ended December 31, 2005
	Schedule D-5	Cost of Common Equity for Year Ended December 31, 2005

The title of each schedule generally describes its contents, and each schedule is patterned after the example included in the instructions for the Commission's filing requirements.

Q. What were the results of Section A?

A. As shown on Schedule A-1 of Exhibit A-1, based on the rate of return on equity approved in its last general rate case, SEMCO Gas's current rates are deficient by $9,487,619 on an annual basis. Again, this de-

ficiency is prior to adjustments to normalize data, eliminate non-recurring items, account for known and measurable changes, and reflect other regulatory conventions.

III. SECTION B

Q. Briefly describe Section B of SEMCO Gas's rate filing?

A. In Section B, the results of operations during the historical year ended December 31, 2005 are converted to a representative 2007 test year, which serves as the basis for establishing new rates.

Q. Which schedules in Section B are you sponsoring?

A. I am sponsoring in whole or in part the following exhibits and schedules, all of which were prepared by me:

Exhibit	Schedule	Title
Exhibit A-7	Schedule A-1	Computation of Revenue Deficiency for the 2007 Test Year
	Schedule A-2	Comparison of Revenue Deficiency between the Historical Period and 2007 Test Year
	Schedule A-3	Reconciliation of Revenue Deficiency for the 2007 Test Year to the Historical Period
	Schedule A-4	Computation of Revenue Multiplier for the 2007 Test Year
Exhibit A-8	Schedule B-1	Average Rate Base for the 2007 Test Year
	Schedule B-2	Net Plant for the 2007 Test Year
	Schedule B-3	Balance Sheet Working Capital for the 2007 Test Year
	Schedule B-4	Peninsular Gas Rate Base Adjustments
	Schedule B-7	CIS System Rate Base Adjustment
	Schedule B-8	FOS System Rate Base Adjustments

	Schedule B-9	Accumulated Depreciation Adjustments
Exhibit A-9	Schedule C-1	Net Operating Income Adjustments for the 2007 Test Year
	Schedule C-2	Adjusted Net Operating Income for the 2007 Test Year
	Schedule C-3	Adjusted Net Operating Income-Income Tax Savings for the 2007 Test Year
	Schedule C-4	Interest Synchronization Adjustment for the 2007 Test Year
	Schedule C-10	Uncollectible Accounts Expense Adjustment
	Schedule C-11	Rate Case Expense Adjustment
	Schedule C-12	Inflation Adjustment
	Schedule C-13	Additional Depreciation and Amortization Expense Adjustment
	Schedule C-16	CIS System Operating Expense Adjustment
	Schedule C-17	FOS System Operating Expense Adjustment
Exhibit A-10	Schedule D-1	Overall Rate of Return Summary for the 2007 Test Year
	Schedule D-2	Cost of Long-term Debt
	Schedule D-3	Cost of Short-term Debt
	Schedule D-4	Cost of Preferred Stock
	Schedule D-5	Cost of Common Equity
	Schedule D-6	Investor-Supplied Capital
	Schedule D-7	Dividend Yield
	Schedule D-8	Earnings Growth Rates
	Schedule D-9	Sustainable Growth Rates
	Schedule D-10	Other Growth Rates
	Schedule D-11	Capital Asset Pricing Model
	Schedule D-12	Gas Utility Group Data
	Schedule D-13	Authorized Rates of Return
	Schedule D-14	Realized Rates of Return
	Schedule D-15	ARP Capital Charge Rate

Q. What were the results of Section B?

A. As shown on Exhibit A-7, Schedule A-1, after incorporating the various adjustments described by me and other witnesses, and including an overall rate of return of 8.23 percent, SEMCO Gas's current rates are deficient by $18,098,561. Please note, however, that included in current rates and this requested increase is a $4,534,155 allowance for the costs associated with company use and lost and unaccounted-for ("LAUF") gas, which SEMCO Gas proposes to remove and recover through the gas cost recovery ("GCR") process, as explained by Ms. Gardiner in her testimony. Schedules A-2 and A-3 of Exhibit A-7 compare and reconcile, respectively, SEMCO Gas's requested rate increase based on the 2007 test year with the results of operations for the year ended December 31, 2005.

A. Exhibit A-8

Q. What is the purpose of Exhibit A-8?

A. SEMCO Gas's 2007 rate base is developed in Exhibit A-8, with Schedules B-1, B-2, and B-3 summarizing total 2007 rate base, 2007 net utility plant, and 2007 working capital, respectively. Meanwhile, Schedules B-4 through B-11 provide details of the various adjustments made to arrive at 2007 rate base.

Q. Please summarize the adjustments shown on Exhibit A-8, Schedule B-2 to plant in service.

A. Eight adjustments were made to the average plant in service during 2005 to convert it to a 2007 test year balance. The first adjustment

annualizes the original cost of the plant purchased from Peninsular Gas Company on May 1, 2005, with the details and calculations of the amount being shown on Exhibit A-8, Schedule B-4. The second adjustment adds two years (for 2006 and 2007) of non-revenue producing plant based on SEMCO Gas's average annual additions over the last five years. The calculation of the average annual amount is described in the testimony of Mr. Larsen and shown on Exhibit A-8, Schedule B-5. Multiplying average annual non-revenue producing plant additions of $10,553,913 by two years produces an adjustment totaling $21,107,826.

The third and fourth adjustments includes in rate base the $594,028 and $486,095 in manufactured gas plant environmental expenditures SEMCO Gas expects to incur during 2006 and 2007, respectively. The details surrounding these amounts are described in the testimony of Ms. Gardiner and shown in Exhibit A-8, Schedule B-6.

The next three adjustments include in rate base the investment SEMCO Gas is making in new Customer Information System (“CIS”) and Field Order System (“FOS”) systems. Described in the testimony of Mr. Ayers, Exhibit A-8, Schedules B-7 and B-8 show the capital expenditures associated with these programs, including the apportionment between jurisdictions, resulting in the $3,627,619, $1,124,543, and $902,462 additions to rate base.

The last adjustment includes in rate base a $5 million representative level of 2007 expenditures associated with the accelerated bare

steel pipe and compressor replacement program described in the testimony of Mr. Larsen. Combining these adjustments, which total $34,791,762, to the 2005 average plant in service balance results in an adjusted balance for the 2007 test year of $441,546,287.

Q. Please explain the adjustments in the lower portion of Exhibit A-8, Schedule B-2, relating to accumulated depreciation associated with rate base.

A. Seven adjustments were made to increase accumulated depreciation and are developed in Exhibit A-8, Schedule B-9. The first adjustment adds two years of depreciation expense to move the 2005 accumulated depreciation balance on average plant in service forward to the 2007 test year. This adjustment totals $25,910,746. The remaining adjustments to accumulated depreciation are associated with the Peninsular Gas Company assets, 2006 non-revenue producing plant additions, 2005 and 2006 manufactured gas plant environmental expenditures, the CIS and FOS systems, and 2005 construction work in progress, all of which will be placed in service during 2006. Adding these adjustments, which total $28,362,609, to the 2005 average accumulated depreciation balance produces an accumulated depreciation balance for the 2005 test year of $199,806,417.

Q. Please explain the adjustment to working capital on Exhibit A-8, Schedule B-3.

A. The only adjustment to the 2005 average working capital balances was to reflect an increase in SEMCO Gas's investment in gas stored

underground. This adjustment, which is in the amount of $11,449,276, is described in the testimony of Mr. Alger and shown on Exhibit A-8, Schedule B-11.

Q. What then is SEMCO Gas's 2007 rate base?

A. As summarized on Exhibit A-8, Schedule B-1, combining 2007 net utility plant of $250,645,908 and 2007 working capital of $95,359,447 produces a 2007 rate base of $346,005,355.

B. Exhibit A-9

Q. What is the purpose of Exhibit A-9?

A. Exhibit A-9 develops SEMCO Gas's adjusted net operating income for the 2007 test year. In particular, Schedule C-1 of Exhibit A-9 summarizes various adjustments to 2005 revenues and expenses to normalize data, eliminate non-recurring items, account for known and measurable changes, and reflect other standard regulatory conventions to arrive at 2007 test year adjusted net operating income.

Q. Please explain the first adjustment on Exhibit A-9, Schedule C-1.

A. In the course of preparing this rate filing, an error related to federal income tax expenses was found. In particular, $59,446 of income taxes attributable to utility operations was erroneously charged to "below-the-line" operations. The adjustment on line 8 of Exhibit A-9, Schedule C-1 reclassifies this amount by adding it to 2005 federal income taxes in column 11.

Q. Please summarize the adjustments in the first four columns of Exhibit A-9, Schedule C-1.

A. The adjustments in the first four columns of Exhibit A-9, Schedule C-1 relate to revenues. The adjustments shown on line 10 annualize the rate increases for sales and transportation customers that became effective in April 2005 under the settlement in Case No. U-14338. The details of these adjustments are explained by Mr. Alger and are contained in Exhibit A-11, Schedule F-2-3. The next adjustment annualizes the revenues associated with the May 2005 purchase of Peninsular Gas Company, with the details of this adjustment also being explained in the testimony of Mr. Alger and contained in Exhibit A-11, Schedule F-2-1.

The next revenue-related adjustment, shown on line 12, reflects the reclassification of general sales customers into their proper rate class (Exhibit A-11, Schedule F-2-2). This is followed by the adjustments on line 13 that account for the effects of abnormal weather during 2005 on sales and transport revenues (Exhibit A-11, Schedule F-2-4). Mr. Alger also sponsors these adjustments.

The next two adjustments on Exhibit A-9, Schedule C-1, relate to other revenues. The first annualizes increases for miscellaneous service fees that became effective in April 2005 as a result of Case No. U-14338, while the second is intended to recognize the additional revenues resulting from proposed increases in charges related to landlord transfer charges. These are addressed in the testimony of

Mr. VanSickle and detailed in Exhibit A-11, Schedules F-3-2 and F-3-3, respectively.

The two adjustments on line 16 of Exhibit A-9, Schedule C-1 are described by Mr. Alger. The first reclassifies certain revenues received from transport customers pursuant to contracts from rate revenues to other revenues, and the second reclassifies amounts for gas received in-kind from revenues to a reduction in the cost of gas, consistent with their treatment in the GCR process (Exhibit A-11, SchedulesF-2-5). The last revenue-related adjustment removes a $350,000 settlement payment from Mirant, which had been in bankruptcy, that was booked to other revenues during 2005 because it is a non-recurring item.

Q. What is the impact of these adjustments on revenues?

A. As shown on column 4 of Exhibit A-9, Schedule C-1, the net effect of the various adjustments to 2005 revenues is an increase of $3,594,200, producing 2007 test year revenues at current rates of $391,361,650.

Q. What are the adjustments in columns 6, 7, 8, and 9 of Exhibit A-9, Schedule C-1?

A. The adjustments in these columns relate to lost and unaccounted-for gas, operation and maintenance expenses, depreciation and amortization expenses, and taxes other than income, respectively.

Q. Please summarize the adjustment in column 6 of Exhibit A-9, Schedule C-1 for company use and LAUF gas.

A. This $1,079,092 adjustment increases company use and LAUF gas expense during 2005 to reflect a five-year average and projected 2007 gas costs. Mr. Alger explains the details of this adjustment, which are contained on Exhibit A-9, Schedule C-5. Please note that, while company use and LAUF gas expense is shown on Exhibit A-9, Schedule C-1, SEMCO Gas proposes to remove this expense from base rates and include it in the GCR process, as explained by Ms. Gardiner.

Q. What is the adjustment on line 21 of Exhibit A-9, Schedule C-1?

A. This adjustment removes $47,151 in disallowable expenses shown in Section A on Exhibit A-3, Schedules C-5 and C-6 and discussed by Mr. Alger.

Q. What is the adjustment shown on line 22 of Exhibit A-9, Schedule C-1?

A. This is an annualization adjustment that adds to SEMCO Gas's 2005 expenses the four months of Peninsular Gas Company's operating expenses prior to its May 2005 purchase. This adjustment is further explained in the testimony of Mr. Warsinske with the details being contained in Exhibit A-9, Schedule C-18.

Q. What is the purpose of the adjustment on Exhibit A-9, Schedule C-1 labeled "Lease Expenses" (line 23)?

A. This adjustment reflects the increased lease expenses SEMCO Gas will incur in 2007. Mr. Alger describes this known and measurable change (Exhibit A-9, Schedule C-6).

Q. What are the next three adjustments shown on lines 24, 25, and 26 of Exhibit A-9, Schedule C-1?

A. These adjustments are discussed by Mr. Warsinske and reflect known and measurable changes in the cost of long-term incentive program, medical and dental expenses, and pension and retiree medical costs (Exhibit A-9, Schedules C-7, C-8, and C-9, respectively).

Q. Please describe the adjustments on lines 27 and 28.

A. These adjustments incorporate the operating expenses associated with the CIS and FOS systems discussed by Mr. Ayers, with the details of the adjustments being contained in Exhibit A-9, Schedules C-16 and C-17, respectively.

Q. What is the adjustment shown on line 29 labeled “Billing Rule Changes”?

A. This adjustment incorporates the net additional costs associated with the Commission’s proposed changes in customer billing rules. This adjustment is discussed in the testimony of Mr. Forsyth, with the details being included in Exhibit A-9, Schedule C-15.

Q. Please describe the adjustment labeled “Uncollectible Accounts".

A. This adjustment includes in the 2007 test year uncollectible accounts expense corresponding to 2007 service revenues. The first step in this adjustment is to determine 2007 service revenues. As shown in the upper portion of Exhibit A-9, Schedule C-10, this was done by first subtracting from 2005 revenues the cost of gas in 2005 and the various revenue-related adjustments described earlier to arrive at 2007

base revenues under current rates. To this amount, the cost of gas in 2007 (based on the Mcf sales and average gas cost developed in Exhibit A-11, Schedule F-2 and Exhibit A-8, Schedule B-10, respectively) and the rate deficiency from Exhibit A-7, Schedule A-1 were added to calculate 2007 service revenues.

The next step is to determine a representative ratio of uncollectible accounts expense, which was based on SEMCO Gas's actual experience over the 5-year period 2001-2005 (calculated removing an unusually large write-off in 2003). This resulting 0.429 percent was then multiplied times 2007 revenues to calculate 2007 uncollectible accounts expense of $2,115,680. From this amount, actual 2005 uncollectible accounts expense was then deducted to calculate the adjustment of $528,600.

Q. Please describe the two adjustments on line 31 of Exhibit A-9, Schedule C-1.

A. These adjustments account for the effects of inflation on SEMCO Gas's operation and maintenance expenses and property and other taxes between 2005 and the 2007 test year. Inflation rates of 2.4 percent for 2006 and 2.1 percent for 2007 were determined from a review of various projections for the consumer price index ("CPI"), which are shown in the footnote on Exhibit A-9, Schedule C-12. As developed in this same schedule, applying these inflation percentages to pertinent operation and maintenance expenses and property and other taxes results in the adjustments for inflation of $1,365,328 and $287,173, respectively, shown on Exhibit A-9, Schedule C-1.

Q. Please describe the adjustment on line 32 of Exhibit A-9, Schedule C-1 labeled “Additional Depreciation and Amortization Expense”.

A. This adjustment is the counterpart to the accumulated depreciation adjustments described earlier in connection with rate base. In particular, it includes in 2007 revenue requirements the depreciation and amortization expenses associated with annualizing the Peninsular Gas Company acquisition, the investment in 2006-2007 non-revenue producing plant additions, manufactured gas plant environmental expenditures, the investment in the CIS and FOS systems, the 2007 expenditures under the ARP, and construction work in progress. The components of this adjustment are developed in Exhibit A-8, Schedule C-13.

Q. Please describe the adjustment on line 33 of Exhibit A-9, Schedule C-1.

A. The $79,793 adjustment increases 2005 rate case expenses to reflect the 3-year amortization of those expected to be incurred in connection with this case. The details of this adjustment are presented in Exhibit A-9, Schedule C-11.

Q. What are the adjustments on lines 34 and 35 of Exhibit A-9, Schedule C-1?

A. The first adjustment, labeled “Proforma Income Tax Savings” reflects the effect on income taxes of differences between SEMCO Gas’s 2005 capital structure and that used to calculate its overall rate of return (Exhibit A-9, Schedule C-2). Meanwhile, the adjustment labeled “In-

terest Synchronization" relates to the amortization of investment tax credits and is developed in Exhibit A-9, Schedule C-3.

Q. Please describe the entries in columns 10 and 11 of Exhibit A-9, Schedule C-1.

A. These adjustments reflect the corresponding effects of the various adjustments to revenues and expenses discussed above on SEMCO Gas's Michigan Single Business Tax and federal income tax liabilities at marginal tax rates of 1.9 percent and 35 percent, respectively.

Q. What is the end-result of all of the adjustments described above?

A. As shown at the bottom of Exhibit A-9, Schedule C-1, after the adjustments described above are made to 2005 results of operations, for the 2007 test year SEMCO Gas's current rates are producing net operating income of $16,935,693.

C. Exhibit A-10

Q. What is the purpose of Exhibit A-10?

A. Exhibit A-10 develops a fair rate of return to apply to SEMCO Gas's rate base, calculated using the Commission's balance sheet approach.

Q. What rate of return do you recommend be used to establish SEMCO Gas's rates?

A. As reflected in column 8 of Exhibit A-10, Schedule D-1, I recommend that SEMCO Gas be authorized an overall rate of return of 8.23 percent. This rate of return recommendation is based on investor-

supplied capital ratios of 7.43 percent short-term debt, 44.05 percent long-term debt, 0.15 percent preferred stock, and 48.38 percent common equity; average costs of short-term debt, long-term debt, and preferred stock of 5.00, 6.30, and 4.70 percent, respectively, and a rate of return on common equity of 11.90 percent. It is also based on non-investor supplied capital consisting of customer deposits having a 9 percent cost, deferred income taxes having a zero cost, and job development investment tax credits ("JDITC") assigned an 8.92 percent cost. Support for this capital structure and the various component capital costs is contained in the following section of my testimony.

IV. RATE OF RETURN

Q. How did you go about developing your proposed rate of return for SEMCO Gas?

A. My evaluation began with a brief review of the operations and finances of SEMCO Energy and general conditions in the natural gas industry and capital markets. I then developed a mix of capital for use in calculating an overall rate of return using the Commission's balance sheet approach, with investor-supplied capital being based on the capital structure ratios maintained by a group of publicly traded gas utilities. Costs applicable to debt and preferred stock were then determined and various analyses conducted to estimate the cost of equity to the gas utility group. This industry cost of equity was then adjusted to reflect the specific circumstances of SEMCO Gas and the present filing. Finally, the findings of these various analyses were

combined to calculate an overall rate of return to be applied to SEMCO Gas's rate base.

Q. What is the role of the rate of return in setting a utility's rates?

A. Rate of return generally serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors only commit money in anticipation of earning a return on their investment commensurate with that from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the U.S Supreme Court cases of *Bluefield Water Works & Improvement Co.* (1923) and *Hope Natural Gas Co.* (1944), the return on investment allowed a utility must be sufficient to: 1) fairly compensate capital presently invested in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.

A. Operations and Finances

Q. Briefly describe SEMCO Energy.

A. Described in more detail in the testimony of Mr. Dubay, SEMCO Energy distributes and transports natural gas to approximately 287,000 customers in Michigan and 124,000 customers in Alaska. It also owns and operates relatively small businesses involved in propane distribution, intrastate pipelines, natural gas storage, and information technology services. SEMCO Energy was previously involved in the natural gas pipeline construction services business, which it sold in Sep-

tember 2004. At December 31, 2005, SEMCO Energy had total assets of approximately $1 billion and its 2005 revenues totaled some $615 million.

Q. Where does SEMCO Energy obtain most of the external capital used to finance its investment in property, plant, and equipment?

A. SEMCO Energy's common stock is publicly traded on the New York Stock Exchange. At its most recent fiscal year-end, it had outstanding over $520 million in short- and long-term debt. SEMCO Energy's debt is rated double-B by the two major bond rating agencies – Ba2 by Moody's Investor Services ("Moody's") and BB- by Standard & Poor's Corporation ("S&P"). These bond ratings make SEMCO Energy's long-term debt "speculative" and below investment grade, which limits who may invest in SEMCO Energy debt and raises its cost of debt. As Mr. Dubay explains, SEMCO Energy has taken steps to improve its bond ratings, including by issuing common stock and convertible preferred stock in 2005.

B. Natural Gas Utility Industry

Q. Please describe conditions in the gas industry over the last two decades.

A. Beginning in approximately 1980, the natural gas industry was buffeted by decreasing demand and prices, a gas glut, an ever-changing federal regulatory environment, and increased competition among industry participants and with other fuels. These developments spawned striking structural changes not only within the pipeline seg-

ment of the industry but for natural gas local distribution companies as well. At least initially, this process was largely driven by regulatory changes at the federal level, with the Federal Energy Regulatory Commission ("FERC") promoting greater competition in markets for wholesale energy supply. While FERC made the natural gas industry more competitive and broadened the market for gas supplies through its Order Nos. 436, 500, and 636, this dramatic restructuring also introduced considerable uncertainties and dislocations felt heavily by conventional utility systems.

These structural changes on both the demand and supply sides eroded gas utilities' traditional monopoly status, with both pipelines and local distribution companies (or "LDCs") experiencing "bypass" as large commercial, industrial, and wholesale customers sought to acquire gas supplies at the lowest possible cost and, in the process, abandoned traditional "full-service" utility suppliers. LDCs have had to confront new complexities and risks entailed in actively contracting for an economical, secure gas supply. Further, changes in transportation rate design mandated by FERC Order No. 636 shifted greater cost responsibility for pipeline demand costs to low load factor customers and, particularly, to LDCs who purchase transportation services from interstate pipelines. Coupled with an increasingly competitive market environment, these structural changes have resulted in greater business risk and operating leverage.

Q. What other factors are of concern to investors?

A. LDCs and their customers have also had to contend with dramatic fluctuations in gas costs due to extraordinary price volatility in gas markets. Besides discouraging potential customers from choosing natural gas, causing certain existing users to substitute alternative fuels, and leading to decreased customer usage, S&P also recently stated in "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," published in its RatingsDirect (January 17, 2006):

> [C]urrent high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current rating.

S&P subsequently noted in "Key Credit Factors For U.S. Natural Gas Distributors," also published in its *RatingsDirect* (February 28, 2006) that more volatile and higher natural gas prices are contributing to a negative credit outlook for natural gas distribution utilities.

Q. Does this exposure highlight the need for ongoing support of a gas utility's financial strength and ability to attract capital?

A. Yes. Given the significant volatility in natural gas markets and a utility's lack of control over market prices for gas, LDCs must have the financial wherewithal to weather the pressures caused by unfavorable energy market conditions. Because of investors' heightened awareness of the risks associated with higher and more volatile gas prices, supportive regulation remains crucial in preserving gas utilities' financial integrity and access to capital. In "Regulation and Credit Quality

in the U.S. Utility Sector," *RatingsDirect* (January 30, 2003), S&P noted that:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.

More recently, S&P stated in "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," *RatingsDirect* (January 17, 2006) that regulatory decisions have become a "dominant factor" in their assessment of credit quality and concluded that "[c]ontinued regulatory support is paramount to credit quality for LDCs, especially during periods of prolonged high natural gas prices."

Q. Are these the only risks faced by natural gas distribution utilities?

A. No. As Fitch Ratings Ltd ("Fitch") noted in a recent review of the utility industry, "U.S. Power & Gas 2006 Outlook," published in its *Global Power/North American Special Report* (December 15, 2005), apart from exposure to more volatile commodity prices, "over the coming five years ... the sector is increasingly expected to face negative credit factors," including the pressures of rising interest rates and higher capital expenditures (p. 2). In addition, utilities continue to face numerous changes in financial accounting standards, such as those relating to accounting for post-retirement benefits other than pensions, which have regulatory as well as financial reporting implications. As *The Value Line Investment Survey* ("Value Line") reported in its December 17, 2004 edition:

> On the regulated front, utilities are incurring greater operating costs, as a result of higher pension and post-

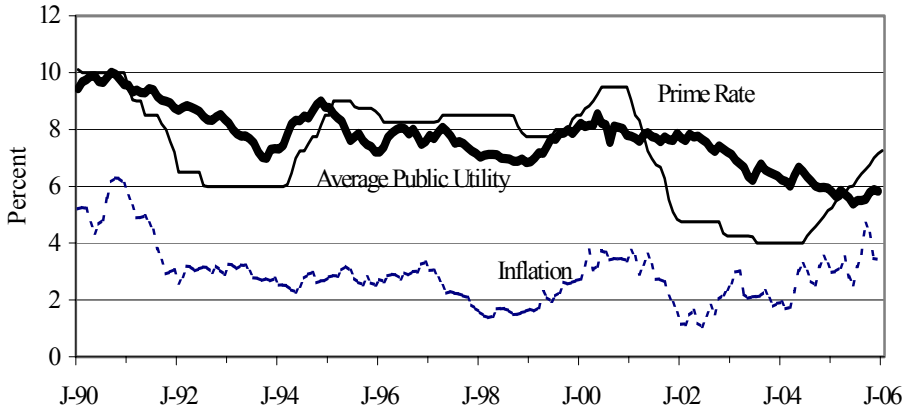
> retirement benefit obligations, in addition to increased medical and property insurance premiums. (p. 459)

Besides these specific problems, LDCs such as SEMCO Gas continue to face many of the same ongoing challenges and risks confronting them in the past, including those related to inflation, weather, rate regulation, customer usage and growth, non-rate regulatory changes, tax law changes, environmental laws and regulations, operating hazards, general economic conditions, and capital market changes, as well as extraordinary risks such as legal liabilities and natural disasters.

C. Capital Markets

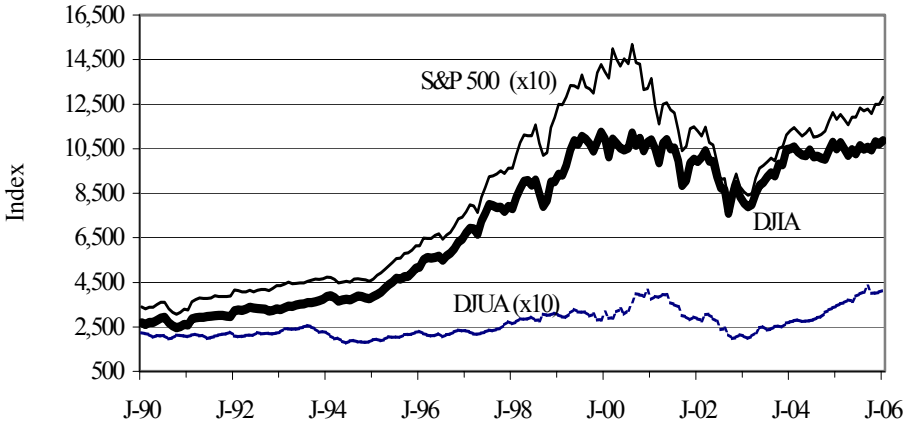
Q. What has been the pattern of interest rates over the last fifteen years?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the CPI since 1990 are plotted in the graph below. After rising to approximately 10 percent in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in the aftermath of the 1991 Gulf war, with rates dipping below 7 percent in late 1993. Yields subsequently rose again in 1994, before beginning a general decline, with investors currently requiring approximately 6 percent from average public utility bonds:



Q. How has the market for common equity capital performed?

A. Between 1990 and early 2000, stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. Although common stock prices have recovered strongly from their lows, the market remains volatile, with share values routinely changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 1990 (the latter two indices were scaled for comparability):



Q. What is the outlook for the U.S. economy?

A. While the economic picture has brightened significantly since the downturn that began in 2001, uncertainties over the durability and pace of economic growth persist, especially in the industrial sections of the country (including Michigan, where SEMCO Gas operates). Government and trade deficits and higher energy prices, which have been exacerbated by the fallout from the natural disasters experienced in the Gulf Coast region, overhang the domestic economy. Continued conflict and instability in Iraq and the ongoing threat of terrorism and nuclear proliferation undermine consumer confidence and contribute to global economic uncertainty. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the U.S. economy.

Q. How do these economic uncertainties affect LDCs?

A. Uncertainties over the extent and durability of the economic recovery have combined to heighten the risks faced by utilities. Stagnation in

economic growth would undoubtedly mean flat or declining gas sales (which, as other witnesses point out, is occurring in SEMCO Gas's MPSC Division's service area), while the potential for increased inflation and interest rates places additional pressure on the adequacy of existing service rates. Meanwhile, higher and more volatile energy prices not only adversely impact gas utilities but the general economy as well. While the economy may continue on a path of fairly steady growth and the volatility in the capital and energy markets may abate, the uncertainties now present may well persist, which increase the risks faced by the natural gas industry, including LDCs.

D. Capital Structure

Q. What is the purpose of this section of your testimony?

A. This section develops a mix of capital for use in calculating an overall rate of return using the Commission's balance sheet approach. Initially, my testimony discusses the implications of capital structure on rate of return, and then it examines the capital structure ratios maintained by SEMCO Energy and other gas companies. Based on these analyses, a mix of capital is developed for use in weighting the respective cost of each source of capital to arrive at an overall rate of return.

Q. What is the role of capital structure in setting a utility's rate of return?

A. Capital structure reflects the mix of capital used to finance a utility's assets. The proportions of total capitalization attributable to each source of capital are typically used to weight the costs of investor-

supplied capital (*e.g.*, debt, preferred stock, and common equity) and, where the balance sheet approach is used to determine rate base, non-investor-supplied capital (*e.g.*, customer deposits and deferred taxes) in calculating an overall rate of return.

Q. Why does this weighting matter?

A. The capital structure ratios determine how much weight is given to a particular source of capital. For investor-supplied capital, because the costs of debt and preferred stock, and the rate of return on common equity, are not the same, this affects the weighted average cost, or overall rate of return, of all sources of capital.

Q. Why are the costs of debt and preferred stock, and the rate of return on common equity, not the same?

A. The reason for this difference is that debt, preferred stock, and common equity have different characteristics that cause investors to demand a higher rate of return to invest in the common stock of a utility versus loan it money through debt or preferred stock.

When investors loan money in the form of debt (*e.g.*, bonds), they enter into a contract whereby the utility agrees to pay the bondholders a specified amount of interest and to repay the principal of the loan in full. The bondholders have a senior claim on available cash flow for these payments, and if the utility fails to make them, they may force it into bankruptcy and liquidation for settlement of unpaid claims. Similarly, when a utility sells investors preferred stock, the utility promises to pay preferred stockholders specified dividends

and, typically, to retire the preferred stock on a predetermined schedule. While the rights of preferred stockholders to available cash flow for these payments are junior to creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last in line are common shareholders, the residual owners of the utility. They only receive cash flow, if any, that remains after all other claimants -- employees, suppliers, governments, lenders, and preferred stockholders -- have been paid. Therefore, the greater the number of investors (*i.e.*, bondholders and preferred stockholders) who have a prior claim on the utility's earnings, the greater the risk to common shareholders. For investors to be willing to bear this additional risk, they require a higher rate of return than lenders and preferred stockholders who have more certain, senior claims on the cash flow of the utility.

Q. Why doesn't a utility finance itself entirely with debt or preferred stock, since these are less expensive sources of capital?

A. If a utility were to attempt to finance itself with 100 percent debt or preferred stock, then there would be no common shareholders. The lenders or preferred stockholders would effectively become the residual owners of the utility, and since they would be exposed to the same risks as if they were common shareholders, they would require a correspondingly higher rate of return as compensation. Accordingly, utilities are generally financed with a mix of debt, preferred stock, and common equity in an effort to produce the lowest overall cost of capi-

tal while, at the same time, permitting the utility to maintain its financial integrity and its ability to attract additional capital on reasonable terms.

Q. How does the use of greater amounts of debt affect the rates of return required by investors?

A. A higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt and preferred stock means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This, in turn, increases the risks to which lenders and preferred stockholders are exposed, and they require correspondingly higher rates of interest and dividends, respectively, for their risk bearing. From common shareholders' standpoint, higher debt and preferred stock ratios mean that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain for them. Again, in accordance with the fundamental risk-return tradeoff principle to be discussed in greater detail later, common shareholders require a correspondingly higher rate of return to compensate them for bearing the greater financial risk associated with a lower common equity ratio.

Q. What sources of investor-supplied capital are used to finance SEMCO Gas?

A. As a division of SEMCO Energy, SEMCO Gas has no independent financing, relying entirely on capital supplied from the general funds of

SEMCO Energy to finance its investment in assets used to provide utility service. SEMCO Energy's capital structure at its most recent fiscal year-end, December 31, 2005, was as follows (thousands):

Capital Component	Amount	%
Long-term Debt	$ 520,559	66.7%
Convertible Preferred	66,526	8.5%
Common Equity	194,000	24.8%
Total	$ 781,085	100.0%

As shown above, SEMCO Energy's permanent capital structure is comprised of approximately 66.7 percent long-term debt, 8.5 percent convertible preferred stock, and 24.8 percent common equity.

Q. What sources of permanent, investor-supplied capital are normally used to finance LDCs?

A. Based on data published by the American Gas Association ("AGA") in its *Gas Facts*, the gas distribution industry maintained the following composite structure ratios between 2000 and 2004:

Capital Component	2004	2003	2002	2001	2000
Long-term Debt	44.0%	43.7%	45.7%	44.8%	44.9%
Preferred	0.1	0.8	1.4	0.8	0.1
Common Equity	55.9	55.5	52.9	54.4	54.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%

This table indicates that LDCs normally finance their investment in utility plant with approximately 44 percent long-term debt and 1 percent preferred stock, with the remaining 55 percent being financed with common equity.

Alternatively, the table below shows the average capital structure ratios between 2001 and 2005 for the group of thirteen publicly

traded companies used as the gas proxy group by MPSC Staff Witness Kirk Megginson in his testimony in Consumers Energy Company's Case No. U-14547:

Capital Component	2005	2004	2003	2002	2001
Long-term Debt	48.9%	45.6%	46.8%	48.3%	48.1%
Preferred	0.2	0.2	1.1	2.6	2.8
Common Equity	51.0	54.3	52.1	49.1	49.1
Total	100.0%	100.0%	100.0%	100.0%	100.0%

As shown above, the average common equity ratio of this gas utility group has generally been in the 50 to 52 percent vicinity, with the average long-term debt ratio of the group typically falling between approximately 47 and 49 percent. Meanwhile, the preferred stock ratio for this group of thirteen gas utilities has ranged from 0.2 to 2.8 percent.

Q. How do the investor-supplied capital structure ratios of SEMCO Energy compare with those maintained by other gas utilities?

A. SEMCO Energy's approximately 67 percent long-term debt and 8.5 percent preferred stock ratios are considerably greater than the 47-49 percent and 0.2-2.8 percent, respectively, normally maintained by the group of gas utilities, with SEMCO Energy's 25 percent common equity ratio being correspondingly below the 50-52 percent industry norm.

Q. Are SEMCO Energy's 2005 year-end capital structure ratios representative of the manner in which it will be financed on an ongoing, prospective basis?

A. No. As described by Mr. Dubay, SEMCO Energy is in the process of addressing its financial condition, in large part by bringing its capitalization ratios back in-line with those maintained by other LDCs. As he also explains, the combined effects of the actions already taken and those underway are expected to restore SEMCO Energy's financial profile to that of an investment grade utility having capital structure ratios consistent with industry norms.

Q. What capital structure ratios are normally used for ratemaking purposes to weight the cost of each source of capital to arrive at an overall rate of return for a utility?

A. It depends. If a utility's capital structure is generally in-line with industry standards, it is customary to use the utility's actual capital structure ratios to calculate its overall rate of return. On the other hand, when a utility's capital structure falls outside of industry norms, it is not uncommon for regulators to base the utility's rate of return on industry capital structure ratios. By using an industry capital structure, rates reflect the reasonable capital costs of providing a particular type of service (*i.e.*, natural gas distribution). In addition, the capital structures maintained by stand-alone, publicly traded companies reflect the capital market's perceptions of the business risks faced by the industry, and the mix of debt and equity required to accommodate these risks. Finally, using capital structure ratios consistent with industry standards permits the cost of common equity to be estimated directly from investors' required rates of return from other gas companies and avoids the necessity of making adjustments to ac-

count for financial risk differences. Indeed, the use of industry capital structure ratios in ratemaking is becoming increasingly common as a result of utilities diversifying their operations into unrelated activities and non-traditional methods being used to finance mergers and acquisitions. Indeed, the Commission used industry capital structure ratios to establish SEMCO Gas's rates in its last two general rate proceedings.

Q. What are the implications of using SEMCO Energy's current capital structure, versus that maintained by the gas utility industry, to calculate the rate of return in this case?

A. As discussed above, SEMCO Energy's current capital structure is not representative of how it will be financed on a permanent basis. Moreover, SEMCO Energy's low common equity ratio implies considerably greater financial risk, because a greater proportion of available cash flow is subject to senior claims. Indeed, this largely explains SEMCO Energy's double-B bond ratings versus an average bond rating for the gas utility group of single-A (Exhibit A-10, Schedule D-12). Moreover, the greater financial risk of SEMCO Energy's lower common equity ratio results in the cost of debt and common equity being significantly higher for SEMCO Energy than for a typical gas utility having lower financial risk. While the effective cost of SEMCO Energy's current capital structure may be temporarily lower than if it were financed according to industry norms because it contains a greater proportion of lower-cost debt, and correspondingly less higher-cost common equity (including associated income taxes), this difference will narrow and

likely ultimately disappear as SEMCO Energy's capitalization ratios move toward industry standards.

Q. What investor-supplied capital structure do you recommend be used to calculate the rate of return for present purposes?

A. I recommend that the rate of return for SEMCO Gas be calculated as it was in Case Nos. U-13575 and U-14338; namely, by using the mix of investor-supplied capital sources currently maintained by other gas utility companies. There are several advantages to using industry capital structure ratios as the basis for calculating the rate of return in this case. First, an industry capital structure comports with the fundamental ratemaking principle that rates should incorporate reasonable costs to provide service. Second, the capital structure ratios maintained by stand-alone, publicly traded gas utilities reflect the capital markets' perceptions of the business risks faced in providing gas distribution service, and the mix of equity and debt required to accommodate these risks. Third, an industry capital structure sufficient to support an investment grade bond rating aids in ensuring that rates are sufficient to meet the Hope and Bluefield standards of maintaining a utility's financial integrity and ability to attract capital on reasonable terms. And, finally, using capital structure ratios consistent with industry standards permits the rate of return on common equity for SEMCO Gas to be estimated from investors' required rate of return from other gas utilities, thus reflecting the relative risks of providing gas distribution service.

Q. Does the use of industry capital structure ratios to establish SEMCO Gas's rates disadvantage customers?

A. No. Prior to 2000, SEMCO Energy's capital structure ratios were generally in-line with natural gas distribution industry standards. Thus, the use of gas utility industry capital structure ratios (coupled with, as will be developed subsequently, industry embedded costs of debt and preferred and a rate of return on common equity based on publicly traded gas utilities) places SEMCO Gas's customers in the same position they would have been had SEMCO Energy's capital structure not deteriorated over the last few years. Indeed, only if SEMCO Energy's actual capital structure ratios and corresponding costs of debt, preferred stock, and common equity reflecting its current bond rating were used would SEMCO Gas's rates reflect the impact of SEMCO Energy's past investment in non-regulated business activities. Moreover, use of SEMCO Energy's actual capital structure ratios to establish rates would impair SEMCO Gas's ability to regain its financial integrity and attract capital on reasonable terms so that it can continue to provide reliable gas service, which is not in customers' long-term best interests.

Q. What specific investor-supplied capital structure ratios do you recommend be used to calculate the rate of return in this case?

A. I recommend using a representative mix of investor-supplied capital based on the ratios maintained by the group of publicly traded gas utilities identified earlier. Because monthly balances are not available, the investor-supplied capital balances at the end of the last four

quarters for each of the thirteen gas utilities were obtained from their Annual Reports and Form 10-Q's (Exhibit A-10, Schedule D-6). From these data, each firm's average short-term debt, long-term debt, preferred stock, and common equity ratios were calculated. These ratios were then combined to calculate the following representative mix of investor-supplied capital for the industry group using the Commission's balance sheet approach:

Capital Component	%
Short-term Debt	7.43
Long-term Debt	44.05
Preferred Stock	0.15
Common Equity	48.38
Total	100.00

Q. How were these industry capital structure ratios applied to arrive at the investor-supplied capital structure for SEMCO Gas?

A. The industry ratios developed above were multiplied times the total investor-supplied capital of $304,659,673 shown on Exhibit A-4, Schedule D-1 to determine the amount attributable to each source of investor-supplied capital. This resulted in the following investor-supplied capital structure for SEMCO Gas:

Capital Component	Amount
Short-term Debt	$ 22,620,981
Long-term Debt	134,202,586
Preferred Stock	456,990
Common Equity	147,379,117
Total	$ 304,659,673

Q. Having determined the amounts of investor-supplied capital, what was the total capital structure for SEMCO Gas using the balance sheet approach?

A. Combining the dollar amounts developed above for investor-supplied capital and the non-investor-supplied sources of capital shown on Exhibit A-4, Schedule D-1 produces the following capital structure for SEMCO Gas, which is also shown on Exhibit A-10, Schedule D-1:

Capital Component	**Amount**	**%**
Short-term Debt	$ 22,620,981	6.78
Long-term Debt	134,202,586	40.23
Preferred Stock	456,909	0.14
Common Equity	147,379,117	44.18
Total Investor-Supplied	$ 304,659,673	91.33
Customer Deposits	2,809,460	.84
Deferred Income Taxes	25,622,394	7.68
JDITC	484,476	.15
Total Non-Investor Supplied	28,916,330	8.67
Total	$ 333,576,003	100.00

E. Embedded Costs

Q. What is the purpose of this section?

A. This section identifies the costs applicable to the various sources of investor-supplied capital, except common equity, and non-investor-supplied capital in the capital structure developed above.

Q. How did you calculate the cost of short-term debt assigned to that component of the capital structure?

A. As developed in Exhibit A-10, Schedule D-3, the current cost of short-term debt for the gas utility industry group is estimated to be

5.00 percent. This cost was arrived at by adjusting the interest rate on short-term debt reported by each company in its 2005 Annual Report or Form 10-K for the change in interest rates between its fiscal year-end and March 2006. For those gas utilities whose short-term debt consisted of commercial paper, the adjustment was based on the change in the 90-day commercial paper rate as reported by Moody's. For those companies with bank loans, the adjustment was based on the change in the London Interbank Offered Rate ("LIBOR"), also as reported by Moody's. These adjustments resulted in the average cost of short-term debt for the industry group increasing from approximately 4.29 percent at fiscal year-end 2005 to a current estimate of 5.00 percent.

Q. What cost is applicable to long-term debt?

A. As developed in Exhibit A-10, Schedule D-2, the average embedded cost of long-term debt at fiscal year-end 2005 for the industry group is 6.30 percent. Please note that the cost of long-term debt for each of the gas utilities shown there is slightly understated because not all debt issuance expenses (including those incurred in connection with refunding expensive debt and replacing it with cheaper debt) were considered, even though these are necessary costs associated with raising debt capital and properly included in the calculation of the total cost of debt.

Q. What is the average cost of preferred stock for the industry group?

A. The embedded cost of preferred stock for the four firms in the industry group having preferred stock outstanding is displayed in Exhibit A-10, Schedule D-4, and averages 4.70 percent. The 4.70 percent average cost of preferred stock is also slightly understated because no consideration was given to issuance expenses associated with selling these securities.

Q. What is the cost of customer deposits?

A. SEMCO Gas presently pays 9 percent interest on deposits from customers.

Q. What is the cost of deferred income taxes?

A. Deferred income taxes arise from timing differences between financial and tax accounting (*e.g.*, straight-line versus accelerated depreciation), and are generally regarded as interest-free loans from the government. Therefore, they have a zero cost for present purposes.

Q. What cost was assigned to JDITCs?

A. Consistent with applicable income tax requirements and Commission policy, the weighted average cost of investor-supplied capital of 8.92 percent, which is calculated on Exhibit A-10, Schedule D-1, was assigned to JDITCs.

F. Rate of Return on Equity

Q. What is the purpose of this section of your testimony?

A. This section estimates the cost of equity to a group of publicly traded gas utilities, which will serve as the basis for determining a fair rate

of return on common equity for SEMCO Gas. Initially, the concept of the cost of equity is examined as the basis for this determination. Next, discounted cash flow ("DCF") and risk premium analyses are conducted, with the results combined with other considerations to arrive at a gas utility industry cost of equity range.

Q. How is a rate of return on common equity customarily determined?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital, since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the "cost of equity" being the minimum rent that must be paid for the use of their money.

Q. What fundamental economic principle underlies this cost of equity concept?

A. The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly accept additional risk only if they expect to be compensated for their bearing that risk. In capital markets where relatively risk-free assets are available, such as U.S. Treasury securities, investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, riskier assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the minimum required rate of return ("k") from an asset ("i") can be generally expressed as:

$$k_i = R_f + RPi$$

where: R_f = Risk-free rate of return; and
RP_I = Risk premium required to hold more risky asset i.

Thus, the minimum required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in certain segments of the capital markets where required rates of return can be directly inferred from market data and generally accepted measures of risk exist. For example, bond yields are reflective of investors' expected rates of return, and bond ratings are indicative of the risk of fixed income securities. The observed yields on government securities and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

To illustrate, average yields during March 2006 on selected U.S. government securities and on public utility bonds of different ratings reported by Moody's are shown in the following table. As evidenced there, as risk increases (measured by progressively lower bond ratings), the required rate of return (measured by yields) rises accordingly. Also shown are the indicated risk premiums over

long-term government securities for the additional risk associated with each bond rating category:

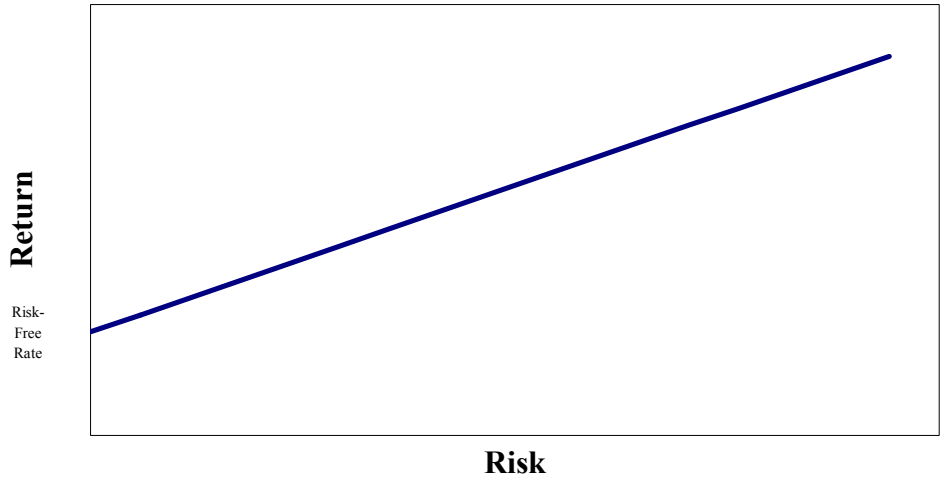
Bond and Rating	March 2006 Yield	Risk Premium Over Long-term Treasury
U.S. Treasury		
5-Year	4.71%	--
Long-term	4.72%	--
Public Utility		
Aa	5.71%	0.99%
A	5.98%	1.26%
Baa	6.26%	1.54%

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. Documenting the risk-return tradeoff for assets other than fixed income securities is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets (*e.g.*, common stock), required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed income securities. Accordingly, it is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets.

The extension of the risk-return tradeoff from assets with observable required rates of return (*e.g.*, bonds) to other assets is represented by the concept of a "capital market line." In particular, competition between securities and among investors in the capital markets drives the prices of assets to equilibrium such that the expected rate of return from each is commensurate with its risk. Thus, the expected rate of return from any asset is a risk-free rate of return plus a

corresponding risk premium. This concept of a capital market line is illustrated below. The vertical axis represents required rates of return and the horizontal axis indicates relative riskiness, with the intercept of the capital market line being the risk-free rate of return.



Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. As discussed earlier, the securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky because mortgage bondholders have a direct claim on the utility's property. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as debentures. The last investors in line are common shareholders. They only receive the net revenues, if any,

that remain after all other claimants have been paid. As a result, the minimum rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of equity for a utility?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the utility specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, by extrapolating interest rates, or through an analysis of other financial data.

Q. Did you rely on a single method to estimate the cost of equity?

A. No. Despite the theoretical appeal of or precedent for using a particular method to estimate the cost of equity, no single approach can be regarded as wholly reliable. Therefore, I used both DCF methods and risk premium methods to estimate the cost of equity. Indeed, it is essential that estimates of investors' minimum required rate of return produced by one method be compared with those produced by other

methods, and that all cost of equity estimates be required to pass fundamental tests of reasonableness and economic logic.

Q. How are DCF models used to estimate the cost of equity?

A. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market valuation process which led to the price investors are willing to pay for a share of a company's common stock. It is predicated on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each share of stock is adjusted by the market so that investors are adequately compensated for the risks to which they are exposed. Therefore, we can look to the market to determine what investors believe a share of common stock is worth, and by estimating the cash flows they expect to receive from the stock in the way of future dividends and stock price, their required rate of return can be mathematically imputed. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, investors presumably used in arriving at that price.

Q. What market valuation process underlies DCF models?

A. DCF models are derived from a theory of valuation which posits that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' re-

quired rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+K_e)^1} + \frac{D_2}{(1+K_e)^2} + \ldots + \frac{D_t}{(1+K_e)^t} + \frac{P_t}{(1+K_e)^t}$$

where: P_0 = Current price per share;
P_t = Future price per share in period t;
D_t = Expected dividend per share in period t;
K_e = Cost of equity.

Q. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires that a number of assumptions be made. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;
- The discount rate exceeds the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;
- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity ("K_e") can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

The constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. Are the assumptions underlying the constant growth form of the DCF model met in the real world?

A. The assumptions required to convert the general form of the DCF model to the constant growth form are never strictly met in practice. In some instances, where earnings are derived solely from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model may be a reasonable working approximation of stock valuation. However, in other cases, where the circumstances cause the required assumptions to be severely violated, the constant growth DCF model may produce widely divergent and meaningless results. This is especially the case if the firm's earnings or dividends are unstable, or if investors are expecting the stock price to be affected by factors other than earnings and dividends.

Q. How did you estimate the cost of equity using the DCF model?

A. The DCF model was applied to the group of publicly traded gas utilities identified earlier, except that KeySpan Corp. was removed because its share price reflects the fact that it is in the process of being acquired by National Grid of Britain. Although slightly different from the group of LDCs I normally use to estimate the cost of equity, this group of twelve gas utilities was accepted in the present instance so as to eliminate one area of controversy.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock.

Q. How did you calculate the dividend yield component of the constant growth DCF model for the gas utility group?

A. Because estimating the cost of equity using the DCF model is an attempt to replicate how investors arrived at an observed stock price, it is essential that all of the components be contemporaneous. Price, dividend, and growth data from different points in time or averaged over long time periods violate the matching principle underlying the DCF model. Therefore, dividend yield was calculated by dividing an estimate of dividends to be paid by each of the gas utilities in the group over the next twelve months, obtained from the index to Value Line's March 17, 2006 edition, by the average closing price of each

firm's stock during March 2006. The expected dividends, representative price, and resulting dividend yield for each of the twelve gas utilities are displayed on Exhibit A-10, Schedule D-7. As also shown there, the average dividend yield for the industry group is 3.9 percent.

Q. Please elaborate on how estimates of investors' long-term growth expectations are customarily developed for use in the constant growth DCF model.

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an effort to replicate the mechanism investors used to arrive at observable stock prices. Therefore, the only "g" that matters in applying the DCF model is that which investors expect and have embodied in current market prices.

Q. What drives investors' growth expectations?

A. Trends in earnings, which ultimately support future dividends and share price, play a pivotal role in determining investors' long-term growth expectations. In "A Study of Financial Analysts: Practice and Theory" published in the *Financial Analysts Journal* (July/August 1999), Stanley B. Block reported the results of a survey conducted to determine what analytical techniques investment analysts actually use. Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securi-

ties. Of the 297 analysts that responded, only three ranked dividends first while 276 ranked it last, with the article concluding:

> Earnings and cash flow are considered far more important than book value and dividends. (p. 88)

The fact that earnings are a key driver of investors' growth expectations is further evidenced by the increasing number of investment advisory services publishing earnings forecasts, including 5-year earnings growth projections.

Q. Please elaborate on these 5-year earnings growth projections.

A. A direct approach to estimate what investors expect in the way of growth is to examine investment advisory services and other sources that report growth projections made by professional security analysts. Whereas examining historical and implied growth rates are indirect approaches that may or may not replicate how investors' expectations are actually formed, looking at security analysts' 5-year earnings growth projections does not require speculation as to what information investors might rely on or how they incorporate this information when formulating their growth expectations. As summarized by Roger A. Morin in *Regulatory Finance: Utilities' Cost of Capital*:

> Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecast to a greater extent than on historic data only. (p. 154)

Q. What are security analysts currently projecting in the way of 5-year earnings growth for the gas utilities in the group?

A. The 5-year earnings growth projections for each of the twelve gas utilities reported in the March 17, 2006 edition of Value Line, First Call's *Institutional Brokers Estimate System* ("I/B/E/S") growth projections reported in the March 2006 edition of S&P's *Earnings Guide*, and by Zacks are displayed on Exhibit A-10, Schedule D-8, with the averages for the group being summarized in the following table:

Value Line	5.7%
I/B/E/S	5.5%
Zack's	5.7%

Also shown on Exhibit A-10, Schedule D-8 are the 10-year and 5-year historical earnings growth rates for each of the twelve gas utilities, which average 5.5 and 8.5 percent, respectively, for the industry group.

Q. How else are investor expectations of future long-term growth prospects for a firm often estimated for use in the constant growth DCF model?

A. In DCF theory and practice, growth in book equity comes from the reinvestment of earnings within the business and the effects of external financing. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between variables that determine the "sustainable" growth attributable to these two factors.

Q. How is a firm's sustainable growth estimated?

A. The sustainable growth rate is calculated by the formula:

$$g = br + sv$$

where “b” is the expected earnings retention ratio (one minus the dividend payout ratio), “r” is the expected rate of return earned on book equity, “s” is the percent of common equity expected to be issued annually as new common stock, and “v” is the equity accretion ratio. The “br” term represents the growth from reinvesting earnings within the firm while the “sv” term represents the growth from external financing. This external financing growth results because existing shareholders share in a portion of any excess received from selling new shares at a price above book value.

Q. What growth rate does the sustainable growth method suggest for the gas utility group?

A. The sustainable growth rates for each of the gas utilities in the industry group based on the projected retention ratios and earned rates of return implicit in Value Line's projections for 2009-2011 are developed in Exhibit A-10, Schedule D-9. As shown there, the sustainable growth method implies an average expected growth rate from earnings retention of 6.3 percent and from external financing of 1.0 percent, for a total growth rate for the gas utility group of 7.3 percent.

Q. What are other projected and historical growth rates for the industry group?

A. Exhibit A-10, Schedule D-10 displays Value Line projected growth rates and 10- and 5-year historical growth rates in book value per

share, dividends per share, and stock price for each of the twelve gas utilities in the industry group. The averages for the group range from 2.8 percent (projected price growth) to 7.0 percent (10-year historical price growth). Besides the fact that many of these growth rates, when combined with the group's dividend yield, imply a cost of equity that barely exceeds the interest rate on much less risky utility bonds, the wide variation in these other growth rates results in them providing limited guidance as to the prospective growth that investors expect from the group of gas utilities.

Q. What is your conclusion as to the growth that investors expect from the industry group?

A. Giving primary weight to security analysts' earnings growth projections of 5.5 to 5.7 percent and projected sustainable growth of 7.3 percent, as well as some consideration to historical earnings growth of between 5.5 and 8.5 percent, I concluded that investors expect growth from the gas utility group of at least between 5.5 and 6.5 percent. Please note that this growth rate range may well be understated given that Zack's reports a 5-year projected earnings growth for its gas distribution utility industry as a whole of 7.2 percent.

Q. What DCF cost of equity does this growth rate ranges imply for the gas utility group?

A. Summing the group's average dividend yield of 3.9 percent with a growth rate range of 5.5 to 6.5 percent produces a DCF cost of equity estimate to the industry group of between 9.4 and 10.4 percent.

Q. How else did you estimate the cost of equity?

A. The cost of equity to the gas utility group was also estimated using the risk premium method. The risk premium method to estimate investors' minimum required rate of return is an extension of the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by determining the additional return investors require to forego the relative safety of bonds and bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds.

Q. How did you implement the risk premium method?

A. I used two approaches to estimate the cost of equity to the industry group under the risk premium method. The first was a forward-looking application of the Capital Asset Pricing Model (CAPM), with the second being a risk premium model based on rates of return on equity authorized LDCs.

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that serves as the basis for current financial education and management. Under the CAPM, investors are assumed to be fully diversified, so the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, which is measured using a "beta" coefficient. Beta reflects the tendency of a stock's price to follow changes in the market, with stocks having a beta less than 1.00 being considered

less risky and stocks with a beta greater than 1.00 being regarded as more risky. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j (R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free interest rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

While the CAPM is not without controversy, it is a routinely referenced in the financial literature and in regulatory proceedings, and firms' beta values are widely reported.

Q. How did you apply the CAPM?

A. I applied the CAPM by first determining investors' required rate of return from a market portfolio. Because the CAPM is an expectational (*i.e.*, forward-looking model), the market cost of equity was estimated by applying the DCF model to the 362 firms in the S&P 500 paying cash dividends, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. The expected dividend yield for each firm was obtained from Value Line, with the expected growth rate being based on the 5-year earnings forecasts published for each firm by Value Line, I/B/E/S, and Zacks. As shown in footnote (a) on Exhibit A-10, Schedule D-11, summing the 2.11 percent expected dividend yield for this market group, which is composed primarily of non-regulated firms, with the average Value Line, I/B/E/S, and Zacks projected growth rate of 11.13 percent produced a required rate of return from the market portfolio (R_m) of 13.24 percent.

Q. What was the next step?

A. The next step was to calculate a market risk premium, which was done by subtracting the average yield on 30-year Treasury bonds during March 2006 of 4.72 percent from the 13.24 percent expected return on the market portfolio. This produced a market risk premium of 8.52 percent. A risk premium for the gas utility group was then calculated by multiplying the 8.52 percent market risk premium by the group's average beta of .82 obtained from Value Line (Exhibit A-10, Schedule D-12). This resulted in a gas utility industry risk premium of 6.96 percent.

Q. What cost of equity is produced for the gas utility group using the CAPM?

A. As shown in Exhibit A-10, Schedule D-11, summing the March 2006 30-year Treasury bond yield of 4.72 percent with the 6.99 percent industry risk premium results in CAPM cost of equity estimate for the gas utility group of 11.71 percent. This lower cost of equity for the industry group relative to the market portfolio is consistent with the risk-return trade-off principle and the fact that gas utilities are generally regarded as less risky than firms operating in the competitive sector.

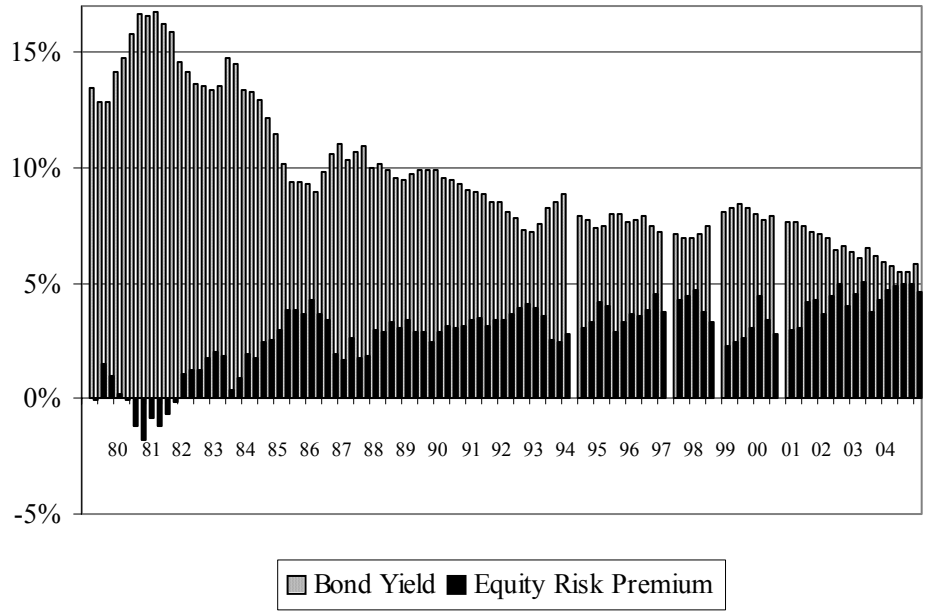
Q. How else did you estimate the cost of equity to the gas utility group using the risk premium method?

A. My second risk premium approach was based on rates of return on equity authorized natural gas distribution companies and is predicated

on the presumption that allowed returns reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. A current risk premium was estimated based on the difference between past authorized returns on equity and then-prevailing interest rates. This risk premium was then added to current interest rates to estimate the cost of equity to the industry group.

Q. Is there any risk premium behavior that needs to be considered when implementing this approach?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant, and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. To illustrate, the following graph plots the yield on public utility bonds (shaded bars) and equity risk premiums implied by the rates of return on common equity (solid bars) authorized for gas distribution utilities between 1980 and 2005 from Exhibit A-10, Schedule B-13:



This graph clearly demonstrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa, with the implication of this inverse relationship being that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a one percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points, respectively. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if present interest rate levels have changed since the time the equity risk premiums were estimated.

Q. Please describe how you applied this second risk premium approach.

A. The rates of return on common equity authorized electric, gas, and telephone utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates, Inc. (RRA) and pub-

lished in its *Regulatory Focus* report. In Exhibit A-10, Schedule D-13, the average yield on single-A public utility bonds is subtracted from the average rate of return on common equity authorized natural gas utilities to calculate equity risk premiums for each quarter between 1980 and 2005. Over this 26-year period, these equity risk premiums for gas utilities averaged 2.86 percent, with the yield on single-A public utility bonds averaging 9.64 percent during the same time period.

To account for the fact illustrated earlier that equity risk premiums do not move in lockstep with interest rates, a regression analysis was performed to quantify this inverse relationship. As shown at the bottom of Exhibit A-10, Schedule D-13, the regression equation indicates that the equity risk premium for gas utilities increases approximately 47 basis points for each percentage point drop in the yield on single-A public utility bonds. With the yield on single-A public utility bonds in March 2006 being 5.98 percent, this implied a current equity risk premium for gas utilities of 4.59 percent.

Q. What cost of equity is implied for the gas utility group by this risk premium approach based on authorized rates of return?

A. As shown on Exhibit A-10, Schedule D-12, the average bond rating of the gas utility group is single-A. Adding the 4.59 percent equity risk premium developed above to the March 2006 yield on single-A utility bonds of 5.98 percent implies that the cost of equity for the industry group is 10.57 percent.

Q. What is the cost of equity range for the gas utility group using the risk premium method?

A. Based on a forward-looking application of the CAPM and an analysis of authorized rates of return on equity, the risk premium method indicates a cost of equity range for the industry group between approximately 10.6 and 11.7 percent.

Q. What do your DCF and risk premium analyses imply as to the cost of equity range for the gas utility group?

A. The analyses described above imply that the cost of equity for the gas utility group is in the range of 10.25 to 11.25 percent. This range overlaps the upper portion of the 9.4 to 10.4 percent range found using the DCF model and the lower end of the 10.6 to 11.7 percent range indicated by the risk premium method.

Q. Are there any other costs properly considered in setting a utility's allowed rate of return on common equity?

A. Yes. The common equity used to finance utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of

funds a utility nets when it issues common equity. In this regard, it is noteworthy that SEMCO Energy issued $30 million of new common stock in 2005 and may issue more in its effort to move to a capital structure consistent with an investment grade company.

Q. Is there an established mechanism for a utility to recognize common equity flotation costs?

A. No. While debt flotation costs are recorded on the books of the utility and amortized over the life of the issue, serving to increase the effective cost of debt capital, there is no similar accounting treatment to ensure that common equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the common equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base since neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Even though there is no accounting convention to accumulate and amortize the flotation costs associated with past common equity issues, flotation costs are a necessary expense of obtaining equity capital. And unless some provision is made to recognize these past issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds.

Q. How can common equity flotation costs be recognized in revenue requirements?

A. As indicated above, there is no direct mechanism to recognize flotation costs necessarily incurred in connection with the issuance of common stock as there is with debt. Therefore, flotation costs must be accounted-for indirectly, with an upward adjustment to the "bare-bones" cost of equity identified above being the most logical and prevalent mechanism to reflect these costs.

Q. How is the magnitude of the adjustment to the bare-bones cost of equity to account for flotation costs determined?

A. There are any number of ways in which a flotation cost adjustment can be calculated, with the adjustment ranging from just a few basis points to more than a full percent. For example, relating past flotation costs to total book common equity normally results in a nominal flotation cost adjustment of a few basis points, while adjusting the bare-bones cost of equity to encourage a target market-to-book ratio of, say, 110 percent, typically produces a flotation cost in excess of one percent. More modest approaches to calculating flotation cost adjustments, such as applying an average flotation cost expense percentage (*i.e.*, 3 to 5 percent) to a utility's dividend yield, or its bare-bones cost of equity, usually result in flotation cost adjustments of between 15 and 50 basis points. Because the precise calculation of a flotation cost adjustment is problematic, rather than make a specific adjustment to the cost of equity, unrecovered flotation costs are

often recognized by selecting the rate of return on common equity from above the mid-point of the cost of equity range.

Q. Is there currently anything else reasonably considered in selecting a point estimate from the cost of equity range?

A. Yes. Since early 2001, a great deal of attention has been focused on the actions of the Federal Reserve Board ("Fed") as it successively encouraged a lowering of short-term interest rates to stimulate a weakening U.S. economy, and then beginning in mid-2004 promoted an increase in short-term interest rates to control a rebounding economy and the prospects for higher inflation. Although short-term interest rates have risen dramatically in response to the Fed's actions, long-term interest rates have only recently begun to show signs of increasing. However, it is generally expected that long-term interest rates will rise in the near-term, which suggests that the cost of permanent capital, including common equity, will be higher over the next few years than it is currently.

Q. How do current interest rates on long-term bonds compare with those projected for the next couple of years?

A. The table below compares current interest rates (as reported by Moody's) on 10-year Treasury, 30-year Treasury, and triple-A corporate bonds with those projected for 2006, 2007, and 2008 (where available) by Value Line in its "Forecast for the U.S. Economy" (February 24, 2006), GlobalInsight in its *The U.S. Economy: The 25-Year Focus* (Third Quarter 2005), Blue Chip Financial Forecasts (April 1.

2006), and The Federal Reserve Bank of Philadelphia's survey of forecasters (February 13, 2006):

	March 2006	2006	2007	2008
10-Year Treasury				
Value Line	4.7	4.7	5.0	5.3
GlobalInsight	4.7	5.0	5.2	5.1
Blue Chip Forecast	4.7	4.8	5.0	N/A
Philadelphia Fed	4.7	4.8	5.0	N/A
30-Year Treasury				
Value Line	4.7	4.8	5.3	5.6
GlobalInsight	4.7	5.2	5.4	5.7
Blue Chip Forecast	4.7	5.0	5.1	N/A
Philadelphia Fed	4.7	N/A	N/A	N/A
AAA Corporate				
Value Line	5.5	5.3	6.0	6.2
GlobalInsight	5.5	6.1	6.3	6.6
Blue Chip Forecast	5.5	5.8	6.0	N/A
Philadelphia Fed	5.5	5.8	6.1	N/A

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in 2007 and 2008 than it is currently,

Q. How should this fact be incorporated into a utility's authorized rate of return?

A. So that the rates being established in this proceeding reflect the capital costs prevailing when those rates are in effect, an adjustment to the current cost of equity is necessary to account for the higher capital costs expected in 2007 and beyond. However, while there is a consensus that capital costs will be higher in 2007 and 2008 than they are currently, there is some disagreement about the magnitude of the increase. Therefore, as with flotation costs, rather than make a specific adjustment to the cost of equity, I recommend that the higher

capital costs expected when rates are in effect be accommodated by selecting the rate of return on common equity from the upper end of the cost of equity range.

Q. What then is your conclusion as to a fair rate of return on common equity for the gas utility group?

A. Consideration of flotation costs and the expected increase in interest rates both argue for a rate of return on equity from the upper end of the 10.25 to 11.25 percent cost of equity range developed earlier. Therefore, to account for these two factors, I conclude that a fair rate of return on common equity for the industry group is at the top of the range, or 11.25 percent.

Q. Are there any checks of reasonableness on this industry rate of return on common equity?

A. Yes. First, the rate of return Value Line projects that each of the twelve gas utilities in the industry group will earn on book equity during the 2009-2011 timeframe is displayed on Exhibit A-10, Schedule D-12. The average for the group is 13.7 percent, and even excluding the two highest values, the remaining ten gas utilities are expected to earn an average of 12.0 percent. Both values indicate that the 11.25 percent industry rate of return on common equity is reasonable.

Second, *Mergent's Public Utility Manual* published stock price and dividend data between 1952 and 2001 for a group of natural gas distribution utilities. Over this 50-year period, the average rate of return realized from an investment in the common stocks of this group

of LDCs has exceeded that from an investment in single-A public utility bonds by 5.26 percent. Even though this series is no longer published, investors may still use it as a comparative benchmark. Accordingly, adding the 5.26 percent equity risk premium to the March 2006 yield on single-A public utility bonds of 5.98 percent suggests that investors may expect a return from gas utilities on the order of 11.24 percent. This check also supports the reasonableness of my 11.25 percent industry cost of equity.

G. Rate of Return on Equity for SEMCO Gas

Q. Is this gas utility industry cost of equity directly applicable to SEMCO Gas?

A. No. Based on Value Line data, the average market capitalization of the group of twelve gas utilities is approximately $1.9 billion (Exhibit A-10, Schedule D-12) versus SEMCO Energy's market capitalization of approximately $175 million. For a variety of reasons (*e.g.*, more diversification, increased resources, and greater share marketability and liquidity), larger firms are considered by the investment community to be less risky than smaller firms, other things being the same. This size relationship is well established and widely documented in the financial literature (*e.g.*, Eugene F. Fama and Kenneth R. French – "The Cross-Section of Expected Stock Returns", *The Journal of Finance* (June 1992)). Therefore, even when using an industry capital structure, an adjustment needs to be made to the industry cost of eq-

uity to account for SEMCO Energy's considerably smaller size relative to the average of the firms in the gas utility group.

Q. What is the magnitude of the adjustment necessary to account for the difference in size between the industry group and SEMCO Energy?

A. Extensive analyses of firm size and returns are included in one of the most frequently cited reference on rates of return, Ibbotson Associates' *Stocks, Bonds, Bills and Inflation*. In their *2006 Yearbook*, rate of return data are presented for publicly traded firms by size decile. The gas utility group's approximately $1.9 billion average size places it between the fifth and sixth deciles, while SEMCO Energy's $175 million market capitalization places it between the ninth and tenth deciles. According to the Ibbotson Associates' data, investors require at least an additional 103 basis points to compensate for SEMCO Energy's much smaller size relative to the larger LDC industry group. Therefore, a size adjustment of approximately 1.0 percent needs to be added to the 11.25 percent rate of return on common equity for the gas utility group to make it applicable to SEMCO Gas.

Q. Is an adjustment to SEMCO Gas's rate of return on common equity required to account for the various changes it is proposing in its rate design?

A. As summarized by Ms. Gardiner, SEMCO Gas is proposing four principal changes in the structure of its rates:

1) Fixed monthly service charge for residential customers;
2) Recovery of company use and LAUFgas through the GCR process;

3) True-up of uncollectible accounts expenses; and
4) Accelerated main and compressor replacement program ("ARP")

Of these four rate design proposals, in my view, only adoption of the fixed monthly service charge might have a measurable effect on SEMCO Gas's investment risk and warrant an adjustment to SEMCO Gas's rate of return on equity.

Q. Why wouldn't SEMCO Gas's proposal to include LAUF gas costs in the GCR process or, alternatively, in a "true-up" mechanism, warrant an adjustment to its rate of return on common equity?

A. LAUF gas costs are not normally treated as a component of gas utilities' base rates, as is currently the case with SEMCO Gas. Rather, the customary practice across the U.S. is to treat the cost of LAUF gas as part of the cost of gas, as SEMCO Gas is proposing. Therefore, the industry cost of equity estimated earlier essentially presumes that LAUF gas costs will be fully recovered (subject, of course, to a review of reasonableness) through the cost of gas. Indeed, it is arguable that if LAUF gas costs continue to be included in SEMCO Gas's base rates, then an upward adjustment to the industry cost of equity would be necessary to account for the uncertainty associated with the collection of this volatile expense. Ms. Gardiner's testimony illustrates this point, by describing SEMCO Gas's experience with LAUF gas costs in 2005.

Q. What adjustment to SEMCO Gas's rate of return on common equity is necessary for its proposed annual true-up of uncollectible accounts expense?

A. SEMCO Gas's proposal to true-up uncollectible accounts expense involves only the incremental amount above or below the uncollectible accounts expense included in base rates and is intended to make sure that SEMCO Gas neither under- nor over-collects this item. So long as a realistic allowance for uncollectibles accounts expense is included in base rates, whether it is trued-up is not likely to be a major area of concern to the investment community. As a result, SEMCO Gas's proposed true-up is not apt to have a material effect, one way or the other, on investors' required rate of return.

Q. What about SEMCO Gas's proposed ARP?

A. SEMCO Gas's proposed ARP is essentially a substitute for allowance for funds used during construction ("AFUDC") on specific incremental investment and is intended to keep it whole between rate cases. Mr. Ketchum's testimony elaborates on this point. The ARP would reduce regulatory lag associated with SEMCO Gas's additional investment in steel pipe and compressor replacements and allow it to recover its capital carrying costs in a more timely fashion. Gas utilities across the U.S. are increasingly being allowed similar recovery of capital costs on selected investments, but because these provisions typically apply to only a small percentage of new investment, they do not have a significant impact on investors' perceptions of overall risk and, in turn, the cost of equity.

Q. Returning to SEMCO Gas's proposed fixed monthly service charge for residential customers, how would it affect investors' perceptions of SEMCO Gas's risk?

A. In my view, SEMCO Gas's proposed fixed monthly service charge for residential customers would have two fundamental effects. First, it would eliminate the impact that colder- or warmer-than-normal weather has on sales margins and earnings. Second, a fixed monthly service charge would eliminate the revenue and earnings losses due to declining use per customer between rate cases.

Q. Should an adjustment to SEMCO Gas' rate of return on common equity be made because the fixed monthly service charge would eliminate SEMCO Gas's weather risk with residential customers?

A. No. The investment community regards all but a couple of the twelve gas utilities in the industry group as having a weather mitigant (*e.g.*, weather normalization adjustment ("WNA") and weather insurance); therefore, the reduced weather risk associated with SEMCO Gas's proposed fixed monthly service charge is, for all intents and purposes, already accounted-for in the cost of equity estimates developed above. This notwithstanding, a WNA does not have a dramatic impact on a gas company's overall investment risk and, in turn, cost of capital, as evident from the following comments by S&P in its May 27, 1991 edition of *Credit Week*:

> All else being equal, S&P would consider the same utility a better credit risk with a weather normalization mechanism than without one. In most cases, this would not mean a higher rating, but a stronger position among utilities within the same rating category. (p. 5)

More recently, Moody's echoed this same position in an October 2002 *Special Report* entitled "Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversification and Warm Weather":

> All other factors being equal, it is better to have rather than *not* have some form of mitigation against warmer than normal weather, although as LDCs evaluate the effectiveness and reliability of their weather mitigants they must also consider the cost/benefit factors.
>
> While the mere use of weather mitigants does not ensure a high credit rating or protect against possible future downgrades, Moody's will be monitoring more closely the effectiveness of an LDCs weather mitigation coverage in protecting operating performance and fixed charge coverage. (p. 1, emphasis in original).

In other words, both S&P and Moody's indicate that the existence or absence of a WNA or other weather mitigant alone does not sufficiently alter the risk of an LDC to warrant a change in its bond rating. Thus, although weather mitigants are generally viewed favorably by the investment community, any impact that they might have on the cost of equity would be measured in just basis, not percentage, points.

It is also noteworthy that WNAs and other weather mitigants are not viewed as entirely positive by the investment community. The reason for this is that, while they dampen the volatility of revenues, they also largely preclude the prospects of exceptional earnings due to an extended cold spell. As noted in S&P's Natural Gas Distribution *Industry Surveys* (November 21, 2002):

> Some LDCs are reluctant to pursue such provisions (weather-normalization), because they don't want to forgo the upside earnings potential of a significantly colder-than-normal winter. (p. 19)

Thus, reductions or increases in the cost of equity due to the existence or absence, respectively, of a weather mitigant tend to be partially offset by an increase in investors' required rate of return to compensate for the loss of upside potential.

Q. What about the effect that the fixed monthly service charge would have with respect to loss of revenues and earnings due to declining use per customer?

A. First, as described by Ms. Gardiner and Mr. Ketchum, gas utilities throughout the U.S. are “decoupling” rates from usage in various ways. Indeed, several of the gas utilities in the group used to estimate the industry cost of equity have mechanisms of one type or another (*e.g.*, AGL Resources and Piedmont Natural Gas) that compensate for declining use per customer. Second, the revenue and earnings losses due to declining use per customer that a fixed monthly service charge would eliminate are only those that occur between rate cases. Use per customer is essentially “reset” in each rate case, so that the loss of revenues and earnings due to declining use per customer can also be ameliorated by more frequent rate cases or other common ratemaking techniques (*e.g.*, recognizing known and measurable changes). As a result, the benefit of a fixed monthly service charge respect to declining customer is that it reduces regulatory lag, with its value depending on the frequency that the utility would otherwise file rate cases to address other expense, investment, and revenue issues.

Q. Does a fixed monthly service charge eliminate the risks faced by SEMCO Gas?

A. Not at all. Weather and declining use per customer are but two of the many risks faced by SEMCO Gas. For example, operating and financing risks related to rate regulation, gas costs, loss of industrial customers, costs disallowances, customer growth, bypass, non-rate regulatory changes, asset impairment, tax laws, environmental laws and regulations, operating hazards, industry restructuring, general economic conditions, inflation, credit requirements, and capital market conditions, just to name a few, remain. Thus, while a fixed monthly service charge may largely eliminate some of the revenue risks associated with the consumption patterns of residential customers, it does nothing to reduce the multitude of other risks faced by SEMCO Gas.

Q. How have you accounted-for the various changes SEMCO Gas is proposing in its rate design in your recommended rate of return on common equity for SEMCO Gas?

A. As discussed above, because industry practice is generally to include LAUF gas costs in the cost of gas, no adjustment for SEMCO Gas's proposal is required. Likewise, because almost all of the gas utilities included in the group used to estimate the industry cost of equity have weather mitigants, the reduced risk associated with this feature of SEMCO Gas's proposed fixed monthly service charge is already largely accounted-for. Therefore, to reflect any benefits from SEMCO Gas's proposed true-up of uncollectible accounts expenses and ARP, and to account-for the reduction in regulatory lag that SEMCO Gas's

proposed fixed monthly service charge provides with respect to declining customer use, I recommend that the 1.0 percent adjustment for SEMCO Energy's smaller size relative to the gas utility group be reduced by approximately one-third to 65 basis points. Thus, adding 65 basis points to the 11.25 percent industry cost of equity produces my recommended rate of return for SEMCO Gas of 11.9 percent.

Q. Are there any qualifications attached to this recommended rate of return on common equity?

A. Yes. My recommended rate of return on equity is predicated on an industry capital structure and the adoption of SEMCO Gas's proposed changes in rates design; if these requests are denied, then a higher rate of return on common equity would be required to compensate for the associated increased risk.

G. Overall Rate of Return

Q. What overall rate of return do you recommend by applied to the rate base of SEMCO Gas calculated using the Commission's balance sheet approach?

A. I recommend an overall rate of return of 8.23 percent. As developed below, this overall rate of return is the result of combining the capital structure developed earlier with the costs of non-investor-supplied capital and investor-supplied debt and preferred stock discussed previously, and an 11.9 percent of return on common equity:

Capital Component	Percent of Total	Component Cost (%)	Weighted Cost (%)
Short-term Debt	6.78	5.00	0.34
Long-term Debt	40.23	6.30	2.53
Preferred Securities	.14	4.70	0.01
Common Equity	44.18	11.90	5.26
Customer Deposits	.84	9.00	0.08
Deferred Income Taxes	7.68	0.00	0.00
JDITC	.15	8.92	0.01
Total	**100.00**		**8.23**

V. APR CAPITAL COST RATE

Q. You noted earlier that SEMCO Gas's proposed ARP is intended to allow it to recover the capital-related costs associated with selected incremental investment until the plant is placed in rate base in a subsequent rate case. How should the capital charge rate, which would be applied to the incremental capital investment, be determined?

A. For ease of administering the ARP, I recommend that the capital charge rate included in the ARP tariff be established in each rate case. This capital charge rate would remain fixed until it was re-established in the next rate case. Besides simplifying administration, such a fixed capital charge rate would disadvantage neither SEMCO Gas nor its customers.

Q. How would the fixed capital charge rate be determined in a rate case?

A. There are three principal costs associated with capital investment – return on investment (including related income taxes), depreciation expense, and property taxes. I recommend the return on investment portion of the capital charge rate be based on the authorized rate of return, with the non-tax deductible capital components being grossed-

up using the revenue multiplier. Meanwhile, the depreciation rate and property tax rate portions of the capital charge rate would be based on the average depreciation rate on plant investment and an average property tax, both determined from data in the rate case.

Q. What capital charge rate do recommend in the present instance?

A. As developed in Exhibit A-10, Schedule D-15, I recommend a capital charge rate for use in SEMCO Gas' proposed ARP of 16.57 percent. This rate consists of the sum of an 11.23 percent pre-tax rate of return (based on my recommended rate of return of 8.23 percent adjusted by a 1.5683 revenue multiplier), an average depreciation rate of 3.19 percent, and an average property tax rate of 2.15 percent.

Q. Does that conclude your direct testimony in this case at this time?

A. Yes, it does.

Attachment A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration, University of Colorado at Boulder (Jan. 1977 to Dec. 1978)	Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.
Teaching Assistant, University of Texas at Austin (Jan. 1973 to Dec. 1976)	Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.
Internal Auditor, Sears, Roebuck and Company, Dallas, Texas (Nov. 1970 to Aug 1972)	Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.
Accounts Payable Clerk, Transcontinental Gas Pipeline Corp., Houston, Texas (May. 1969 to Aug. 1969)	Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics, University of Texas at Austin (Sep. 1974 to May 1980)	Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*
M.B.A., Finance and Accounting, University of Texas at Austin, (Sep. 1972 to Aug. 1974)	Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues. Professional Report: *Planning a Small Business Enterprise in Austin, Texas*
B.B.A., Accounting and Finance, Southern Methodist University, Dallas, Texas (Sep. 1967 to Dec. 1971)	Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants and Texas Society of Certified Public Accountants.

Member of Advisory Council, Center for Public Utilities, College of Business Administration and Economics, New Mexico State University.

Member of Financial Management Association, Southwestern Finance Association, and American Finance Association. Participated as session chairman, moderator, and paper discussant at annual meetings of these and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

Bibliography

Monographs

"On the Use of Security Analysts' Growth Projections in the DCF Model," with William E. Avera, *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds., Institute for Study of Regulation (1982).

"An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies", with William E. Avera, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982).

"The Spring Thing (A) and (B)" and "Teaching Notes", with Mike E. Miles, a two-part case study in the evaluation, management, and control of risk; distributed by *Harvard's Intercollegiate Case Clearing House*; reprinted in *Strategy and Policy: Concepts and Cases*, A. A. Strickland and A. J. Thompson, Business Publications, Inc. (1978) and *Cases in Managing Financial Resources*, I. Matur and D. Loy, Reston Publishing Co., Inc. (1984).

"Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

"Linear Algebra," "Calculus," "Sets and Functions," and "Simulation Techniques," contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

Articles and Notes

"How to Value Personal Service Practices," with Keith Wm. Fairchild, *The Practical Accountant* (August 1989).

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Adrien M. McKenzie, *Public Utilities Fortnightly* (May 25, 1989).

"North Arctic Industries, Limited," with Keith Wm. Fairchild, *Case Research Journal* (Spring 1988).

"Regulatory Effects on Electric Utilities' Cost of Capital Reexamined," with Louis E. Buck, Jr., *Public Utilities Fortnightly* (September 2, 1982).

"Capital Needs for Electric Utility Companies in Texas: 1976-1985", *Texas Business Review* (January-February 1979), reprinted in "The Energy Picture: Problems and Prospects", J. E. Pluta, ed., *Bureau of Business Research* (1980).

"Some Thoughts on the Rate of Return to Public Utility Companies," with William E. Avera, *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978).

"Regulatory Problems of EFTS," with Robert McLeod, *Issues in Bank Regulation* (Summer 1978) reprinted in *Illinois Banker* (January 1979).

"Regulation of EFTS as a Public Utility," with Robert McLeod, *Proceedings of the Conference on Bank Structure and Competition* (1978).

"Equity Management of REA Cooperatives," with Jerry Thomas, *Proceedings of the Southwestern Finance Association* (1978).

"Capital Costs Within a Firm," *Proceedings of the Southwestern Finance Association* (1977).

"The Cost of Capital to a Wholly-Owned Public Utility Subsidiary," *Proceedings of the Southwestern Finance Association* (1977).

Selected Papers and Presentations

"Legislative Changes Affecting Texas Utilities," Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).

"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

"Accounting and Finance Workshop" and "Divisional Cost of Capital," New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).

"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

"Rate Filing – Basic Ratemaking," Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).

"The Effects of Regulation on Fair Market Value: P.H. Robinson – A Case Study," Annual Meeting of the Texas Committee of Utility and Railroad Tax Representatives, Austin, Texas (September 1987).

"How to Value Closely-held Businesses," TSCPA 1987 Entrepreneurs Conference, San Antonio, Texas (May 1987).

"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

"Valuation of Closely-Held Businesses," Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

"Rating Regulatory Performance and Its Impact on the Cost of Capital," New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).

"Effect of Inflation on Rate of Return," Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).

"Original Cost Versus Current Cost Regulation: A Re-examination," Financial Management Association, New Orleans, Louisiana (October 1980).

"Capital Investment Analysis for Electric Utilities," The University of Texas at Dallas, Richardson, Texas (June 1980).

"The Determinants of Capital Costs to the Electric Utility Industry," with Cedric E. Grice, Southwestern Finance Association, San Antonio, Texas (March 1980).

"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

"Issues in Regulated Industries – Electric Utilities," University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).

"Investment Conditions and Strategies in Today's Markets," American Society of Women Accountants, Austin, Texas (January 1979).

"Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies," Financial Management Association, Minneapolis, Minnesota (October 1978).

"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"Public Utilities as Consumer Targets – Is the Pressure Justified?," University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

Attachment B

BRUCE H. FAIRCHILD

SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirement
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity
85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity
110	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska Regula-tory Commission	TA-	Feb-06	Connection Fees

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **SEMCO ENERGY GAS COMPANY** for authority to redesign and increase its rates for the sale and transportation of natural gas in its MPSC Division and for other relief.	)))))))	Case No. U-14893

DIRECT TESTIMONY AND EXHIBIT OF EXPERT WITNESS

Daniel J. Forsyth, P.E.

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Daniel J. Forsyth, P.E.
On Behalf of
SEMCO Energy Gas Company

Q. Please state your full name and business address.

A. My name is Daniel J. Forsyth, and my business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position?

A. My title is Director of Customer and Support Services for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc.

Q. Please describe your academic background, current job duties, and business experience.

A. In 1982, I graduated from Michigan Technological University with a Bachelor of Science degree in Civil Engineering. I hold a State of Michigan Mechanical Contractors License. Additionally, I am a registered professional engineer in the State of Michigan. In my current position, I direct the activities of employees in the customer service function, which includes the call center, service dispatch, billing and credit. I also direct activities in the areas of drafting, fleet, facilities, safety, and training. I have held positions of increasing responsibility, in the areas of field operations, engineering, customer service, and support services at SEMCO Gas since 1982.

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

A. The purpose of my testimony is to discuss the impact of the MPSC Staff's proposed revisions to the residential and commercial customer billing rules on SEMCO Gas. Additionally, I will discuss

the impact on the Company of the emergency billing rules that were promulgated by the Commission in Case No. U-14668. The temporary emergency rules were in effect from November 1, 2005, through March 31, 2006, and are now proposed by the MPSC Staff to be permanent revisions to the residential and commercial billing rules.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit which was prepared under my direction:

Exhibit A-9, Schedule C-15 MPSC Residential and Commercial Billing Rules Proposed Change Impact

Q. Please describe your understanding of the process that is underway at the MPSC to change the Commission's customer billing rules.

A. The MPSC Staff is proposing what I consider to be major revisions to the Commission's existing residential [R 460.2101, et seq.] and commercial [R 460.2071, et seq.] billing rules. My understanding is that these proposed rule revisions must be adopted in accordance with a process prescribed by law, and that process is ongoing at the time I am preparing this testimony.

Q. What is your understanding of the reasons for the proposed customer billing rule changes?

A. My understanding is that the MPSC Staff considers the current customer billing rules to be outdated and is seeking to revamp those rules to make them more user friendly, consistent, clear, and complete. As previously mentioned, my understanding is that the MPSC Staff also proposes to incorporate the emergency rules implemented in the fall of 2005 into the Commission's customer billing rules, on a permanent basis.

Q. When do you expect these proposed rules to be promulgated and effective?

A. I expect the proposed rules to be submitted to the Commission in May 2006, with a final Commission decision on the proposed rules to be issued and in effect by November 1, 2006. The November effective date is intended to ensure that the emergency rules promulgated last year are in effect for the 2006-2007 winter heating season.

Q. Please describe the customer billing rule changes currently proposed.

A. I would characterize the changes to the proposed customer billing rules as a comprehensive revision of the Commission's commercial and residential billing rules and summarize some of those changes received from the MPSC in draft form on May 2, 2006 as follows:

Incorporation of the Emergency Billing Rules. The group of customers eligible for Winter Protection – meaning protection from

termination of service if a reduced payment obligation is met during the heating season – would be expanded and the customer's payment responsibility would be reduced upon incorporation of the Commission's emergency billing rules from last year into the MPSC's permanent billing rules. Additionally, the definition of heating season would be changed to effectively increase the time period for protection by one month. The emergency rules change the responsibility for customers to pay their bills for service, by giving residential customers 22 days instead of 17 days and commercial customers 22 days instead of 21 days to render payment. Also, the ability of utilities to recoup arrearages through settlement agreements with their customers would continue to be restricted by limiting the arrearage payment obligation during the heating season to $50 for residential customers and $100 for commercial customers.

Additional Customer Billing Rule Changes. In addition to adopting the Commission's temporary emergency billing rules as permanent rules, there are many additional proposed changes to the MPSC's customer billing rules. One change includes reducing the utilization of estimated meter readings. It is also proposed that utilities pay interest on amounts overcharged to customers because of billing errors. Another proposal would not only reduce the amount of interest that utilities pay on deposits but also reduce the amount of

the deposit utilities may require before instituting service. There also are proposals to expand the shut-off protection (such as for customers in the military). It is also proposed to separate, by definition, small commercial customers and large commercial customers. The idea is to provide small commercial customers some of the same type of protections as residential customers.

Q. Does the Company believe that the customer billing rule changes, if adopted by the Commission substantially as proposed, will have significant financial impact on SEMCO Gas?

A. Yes. The Company expects to experience a significant financial impact as well as operational and transitional impacts if the proposed customer billing rules are adopted by the Commission in substantially their current form.

Q. Describe in more detail the expected impact on SEMCO Gas when the Commission makes its temporary emergency billing rules a permanent part of its customer billing rules

A. On Exhibit A-9, Schedule C-15, entitled “MPSC Residential and Commercial Billing Rules Proposed Change Impact,” page 1 of 4, I show the financial effect of just four emergency billing rule items that would significantly impact SEMCO Gas when the Commission’s temporary emergency billing rules are made a permanent part of the MPSC’s customer billing rules.

The first item is a change to current Rule 16 of the residential billing rules, to extend the residential bill payment due date from 17 days to 22 days after the bill is rendered, giving residential customers an additional 5 days to pay their bills for service from the Company. The impact on the Company would be the additional carrying costs on amounts owed for service associated with the additional delay in the Company receiving payments from customers after bills are rendered as outlined on page 3 of 4 in my exhibit.

The second item is a change to current Rule 9 of the commercial billing rules, to extend the commercial bill payment due date from 21 days to 22 days after the bill is rendered, giving commercial customers an additional day to pay their bills for service from the Company. As with the change in the due date for residential bills, the impact would be the additional carrying costs on amounts owed for service associated with the additional delay in the Company receiving payments after bills are rendered again as outlined on page 3 of 4 of my exhibit.

The third item is a change to current Rule 74 of the residential billing rules, to alter the household income level that determines a customer's eligibility for "Winter Protection" (i.e., protection from termination of service if a reduced payment obligation is met during the heating season) from 150% of the

federal poverty guidelines to 200% of those guidelines. This change would increase the number of customers who are eligible for Winter Protection. In addition to the eligibility change, the required monthly payment from customers who are eligible for Winter Protection would be decreased from 7% of the estimated annual bill plus a portion of any pre-enrollment arrears to 6% of the estimated annual bill and no monthly payment on pre-enrollment arrears. This change significantly decreases the monthly payment for eligible customers during the heating season and, as a result, increases the customer account arrearage which causes higher payment obligations at the end of the heating season. This subsequently results in higher arrears accumulation for the Company. Increased arrearages for the Company adds to the carrying costs on amounts owed for service by these customers and, in my experience, increases the Company's write-offs. The Company experienced an additional $1,447,330.29 of arrears for Winter Protection customers in the 2005-2006 heating season compared to the 2004-2005 heating season which I attribute to the changes imposed by the emergency billing rules. The financial impact of carrying these additional arrears is outlined on page 3 of 4 in this exhibit.

The final emergency billing rule item to have a substantial impact on the Company involves changes to current residential

billing Rule 34 and Commercial billing Rule 13. The proposed changes alter the deposit rules for customers, requiring the Company to change the way in which it calculates deposits for residential and commercial customers. Having to perform alternative deposit calculations will require the Company to make system software changes, and this, in turn, increases Company costs. The company has not made any significant software changes to the existing Customer Information System (CIS) based on the emergency billing rules being issued for a defined temporary period of time. Manual processes were put in place to address these issues or the Company chose more advantageous criteria for the customer based on CIS limitations. Additionally, in Mr. Ayers testimony, he discusses impacts of implementing a new CIS system. The specifications for this new system were completed before the issuance of the emergency rules, therefore any system functionality required to support the proposed billing rules, which were not included in the specifications for the new CIS being implemented, would require costly modifications.

Q. Describe in more detail the expected impact on SEMCO Gas of the Commission adopting other proposed general billing rule changes.

A. On Exhibit A-9, Schedule C-15, entitled “MPSC Residential and Commercial Billing Rules Proposed Change Impact,” page 2 of 4, I show the financial effect of six proposed general billing rule items

that would significantly impact SEMCO Gas if they were adopted by the Commission.

The first item is the proposed definition “Collection Charge.” The proposed new definition defines the approved charge associated with field collection of a past due account. SEMCO Gas currently charges this fee whenever a representative is dispatched to a customer’s home or business to collect a past due account. This work is usually performed during the field notification process and the actual disconnection process outlined in Rule 52 of the current residential billing rules and Rule 14 of the current commercial billing rules. In the Company’s view, under the proposed definition, the Company could levy a charge only if a representative was dispatched at the time service was to be disconnected. The Company could not levy this charge as part of the field notification process. As a result, the Company would lose the receipt of these charges it currently collects for the performance of these field notifications as outlined on page 4 of 4 in my exhibit. The Company does not anticipate any changes in the field notification process nor is there any change proposed to the rules that govern this process by the MPSC Staff in this rules change process.

The next item is a proposed change to current residential billing Rule 34. The proposed change would reduce the interest

rate utilities pay on deposits from 9% to 7%. This would reduce the interest paid on deposits obligation for the Company.

The third item is a proposed change to current residential billing Rule 12. Under the proposal, there would be a limit on the number of consecutive estimated meter readings on an account if the actual meter reading was outside the premise usage parameters. The Company currently utilizes research by office personal to resolve many of these types of issues before utilizing the more costly option of dispatching a field employee to obtain an additional read. Many of these issues are resolved through the office review or a subsequent scheduled meter read. The impact on the Company from this proposed rule change would be the cost of making additional field meter readings instead of relying on estimated meter readings. I estimate an additional 4,223 accounts would need to be dispatched to field technicians as outlined on page 4 of 4 in my exhibit.

The fourth item is a proposed change to current residential billing Rule 25. Under the proposed rule, the Company would be obliged to pay interest at 7% to any customer who is overcharged due to a billing error. This is an entirely new provision, and would significantly increase the Company's costs, in the amount of the interest paid on these overcharges. In 2005 the Company credited $3,895,402.99 to customers as outlined on page 4 of 4 in my

exhibit. I should add that, in my experience, overcharges for billing errors are unavoidable, despite the Company's efforts to minimize such errors.

The fifth item is a proposed change to current residential billing Rule 25, to impose a fee for any unauthorized use of utility service. The Company currently bills and attempts to collect any consumption as well as any expenses associated with the processing of the unauthorized use, both field and office activities. The impact on the Company, based on my interpretation would be the ability to levy additional fees in cases of theft as outlined on page 4 of 4 in my exhibit, though I am uncertain of the likelihood of collecting such fees.

Finally, proposed changes to current residential billing Rule 21 and Rule 12 will require the Company to make system software changes and thus impose costs on the Company. The proposed change to Rule 21 would require the Company to identify on customer bills tariff related charges from non-tariff related charges. This would require the Company to make programming changes to its CIS to change the billing process to enable the ability to identify these different charges for display on the bill, which is functionality that the CIS system currently does not have. Proposed changes to Rule 13 would require CIS system changes to identify estimated reads on meter edit reports so billing personnel can comply with

estimate limitation provisions in this rule. The current system does not have this programming logic.

Q. What total impact does SEMCO Gas expect from the proposed billing rule changes?

A. The total impact on SEMCO Gas is estimated to be $1,971,293 in increased annual operations and maintenance expense and lost revenue.

Q What portion of this amount is attributable to the proposal that the Commission's emergency billing rules be made a permanent part of the Commission's customer billing rules?

A. The estimated impact of making the emergency billing rules a permanent part of the Commission's customer billing rules is $616,720.60 annually, in additional operating and maintenance expenses.

Q. What portion of this amount is attributable to the proposed general billing rule changes?

A. The estimated impact of the proposed changes to the general billing rules is $1,354,572.57 annually, in additional operating and maintenance expenses and lost revenue.

Q. Do you have anything to add on this subject?

A. Yes. I believe that the data I have presented in my testimony is a reasonable estimate of the impact of the proposed customer billing rule changes on the Company and should be used to establish the

Company's new base rates. If, however, the Commission does not adopt the revised customer billing rules substantially as proposed, it may be necessary to update my calculations to provide a more accurate estimate of the impact of customer billing rule changes on the Company for ratemaking purposes.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF EUGENE N. DUBAY

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Eugene N. Dubay
On Behalf of
SEMCO Energy Gas Company

Q. Please state your full name and business address?

A. My name is Eugene N. Dubay, and my business address is 1411 Third Street, Suite A, Port Huron, MI 48060.

Q. By whom are you employed and what is your position?

A. I am Senior Vice President and COO of SEMCO Energy, Inc. In that position, I am responsible for the day-to-day operations at SEMCO Energy Gas Company ("SEMCO Gas" or the "Company") and ENSTAR Natural Gas Company ("ENSTAR"). Both SEMCO Gas and ENSTAR are divisions of SEMCO Energy, Inc. and are local distribution companies engaged in the transmission, distribution, and sale of natural gas to customers in Michigan and Alaska, respectively.

Q. Please describe your academic background and business experience.

A. I received a Bachelor of Science Degree from the U.S. Naval Academy in 1971 and a Master of Business Administration from Texas A&M University in 1977. I have been registered as a Certified Public Accountant. I have held positions in the utility industry since 1981. I worked for approximately 14 years at Southern Union Company, six years for ONEOK and 3 ½ years for SEMCO Energy, Inc. In that period, I served in a variety of executive level positions, including Chief Financial Officer of Southern Union Company, Executive Vice President of Missouri Gas Energy, and President of Kansas Gas Service, a division of ONEOK.

Q. What is the purpose of your testimony?

A. I am the chief policy witness for the Company. The primary purpose of my testimony is to provide an overview of SEMCO Energy, Inc.'s financial situation, including the particular circumstances that prompted SEMCO Gas's filing of this case with the Michigan Public Service Commission (the "MPSC" or the "Commission"). As part of providing what I would describe as a "big picture" perspective, I want to emphasize the importance of both the Company's revenue increase request and rate design proposals in giving SEMCO Gas a fair opportunity to recover the costs of providing service to customers, including the cost of capital authorized by the Commission in this case. The testimony filed by Ms. Gardiner and the other witnesses in this case describes the specific elements of the Company's revenue increase request and rate design proposals. While I have been closely involved in the development of this filing, those witnesses are familiar with the details of all of the Company's proposals.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits

Exhibit A-12, Schedule 4	SEMCO Energy Gas - MPSC Division 2003 through 2005 Historical Return on Equity
Exhibit A-12, Schedule 5	2005 Best Practices Benchmarking

Q Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What specific topics do you address in your testimony?

A. I address the following topics:

- Overview of SEMCO Energy, Inc. and SEMCO Gas
- SEMCO Energy, Inc.'s Finances and Recent Improvements in Them
- Factors Affecting SEMCO Gas's Results
    - MPSC Division Earned v. Allowed Returns
    - Increased Costs of Providing Service to MPSC Division Customers
    - Rate Design Issues – Volumetric Distribution Charge
    - Rate Design Issues – LAUF Gas Costs
    - Rate Design Issues – Uncollectible Expense
- SEMCO Gas's Relative Efficiency; Comparison to Other Michigan Utilities
- SEMCO Gas's Capital Spending and Constraints

Overview of SEMCO Energy, Inc. and SEMCO Gas

Q. Please describe SEMCO Energy, Inc.

A. SEMCO Energy, Inc.'s primary business segment is a gas distribution business in both Michigan and Alaska serving a combined total of approximately 409,000 customers. As I said earlier in my testimony, the Michigan operations are known as SEMCO Gas, and the Alaskan operations are known as ENSTAR.

Q. Please describe SEMCO Gas.

A. SEMCO Gas is a division of SEMCO Energy, Inc. that serves approximately 281,000 customers in Michigan. About 244,000 customers are served under rates and terms and conditions of service determined by the MPSC, in what is termed the "MPSC Division," with the remaining 37,000 customers currently served under rates and terms and conditions of service determined by the City Commission of Battle Creek, in what is sometimes termed the "Battle Creek Division." Approximately 91% of SEMCO Gas's MPSC Division customers are residential, almost 9% are commercial, and less than half a percent are industrial customers. The Company only transports, distributes, and sells natural gas to its customers. SEMCO Gas is not what is commonly referred to as a "combination company," since it has no electric operations. Because it relies solely on the delivery and sale of a single commodity, the Company operates what is essentially a seasonal business, given the way its revenues are currently collected, with the bulk of its revenues and earnings in the winter heating season from November to March each year. The Company typically incurs losses in the non-heating season each year. Later in my testimony, I will expand on this discussion of key Company characteristics.

SEMCO Energy, Inc.'s Finances and Recent Improvements in Them

Q. Why are you including this section in your testimony?

A. I have included this section on SEMCO Energy, Inc.'s finances and recent improvements in those finances in my testimony to provide additional information that may be useful to the Commission in deciding the issues in the case. This is essentially part of the context for SEMCO Gas's proposals in this case. Where appropriate, I have tried to show the links between things being done by SEMCO Energy, Inc. and benefits to SEMCO Gas.

Q. Please describe SEMCO Energy, Inc.'s recent financial performance and results and, in general terms, its current business strategy.

A. After incurring net losses in both 2003 and 2004, SEMCO Energy, Inc. earned a modest profit of $0.2 million in 2005. SEMCO Energy, Inc.'s current business strategy is to focus on its core utility business (meaning both its SEMCO Gas and ENSTAR operations). From a financial perspective, SEMCO Energy, Inc. is seeking to improve its credit profile in the wake of the divesture or winding down of several unsuccessful non-utility businesses, with the objective of regaining its investment grade credit rating for its senior unsecured debt. SEMCO Energy, Inc. has brought in a new senior management team of experienced utility executives to pursue its new business strategy and effect improvements in SEMCO Energy, Inc.'s finances.

Q. Has SEMCO Energy, Inc. taken actions during the past several years that have improved its financial position?

A. Yes. Over the past several years, SEMCO Energy, Inc. has taken actions to improve its credit profile by increasing the equity component of its capital structure, reducing its cash flow requirements, and improving the risk profile of the Company. To date, as a result of the actions already taken, the Company's long-term debt to total capitalization ratio has decreased from 75.2% at December 31, 2003, to 62.9% at December 31, 2005. (Short-term debt has been excluded in calculating these ratios.) Those efforts have continued in 2006, with the exchange of a portion of SEMCO Energy, Inc.'s Convertible Preferred Stock for cash and shares of Common Stock. In addition, SEMCO Energy, Inc. is actively examining opportunities to refinance higher cost debt with lower cost capital.

Q. What is the benefit of SEMCO Energy, Inc.'s regaining an investment grade rating on its senior unsecured debt?

A. An investment grade rating on SEMCO Energy, Inc.'s senior unsecured debt would reduce the interest expense paid on SEMCO Energy, Inc.'s short-term debt. That short-term debt is funded by a bank credit facility used primarily to finance the purchase of natural gas for resale to customers. The interest rates charged on borrowings under this bank credit facility are based, in part, on SEMCO Energy, Inc.'s credit ratings and, all else equal, would be reduced as the credit ratings improve.

From the Commission's perspective, as SEMCO Energy, Inc. moves towards regaining an investment grade profile, it also becomes

more closely aligned with the industry average capital structure that the MPSC has historically used in determining the rates charged by SEMCO Gas. In my experience, when regulatory agencies set rates in this way, they wish to see that the utility is making progress towards having an actual capital structure that more closely resembles the one used to determine rates charged to customers.

Q. Please describe the recent actions SEMCO Energy, Inc. has taken to improve its credit profile.

A. In March and June 2004, SEMCO Energy, Inc. issued $50 million of Convertible Preference Stock to one investor. This Convertible Preference Stock was issued at a time when SEMCO Energy, Inc. had limited access to capital markets; after SEMCO Energy, Inc.'s senior unsecured credit ratings were downgraded to non-investment grade in 2003. In addition, in June 2004, SEMCO Energy, Inc. retired $30 million of its 8% series long-term debt, and the Common Stock dividend was suspended.

Q. Please continue.

A. In December 2003, SEMCO Energy, Inc. began to seek a buyer for its construction services businesses. In September 2004, those businesses were sold, thereby significantly reducing SEMCO Energy, Inc.'s risk profile and generating approximately $21 million cash that could be utilized in the gas distribution business.

Q. Were there actions taken in 2005 to improve SEMCO Energy, Inc.'s financial profile?

A. Yes, SEMCO Energy, Inc. continued to take actions during 2005 to improve its financial profile. In March 2005, SEMCO Energy, Inc. issued $70 million of Convertible Preferred Stock and used the proceeds to retire higher cost securities, including the Convertible Preference Stock and a portion of its 10.25% Trust Preferred Securities. In addition, in September 2005, SEMCO Energy, Inc. issued $30 million of Common Stock and retired the remaining amount outstanding of its 10.25% Trust Preferred Securities. Subsequent to this financing, Moody's Investors Service raised SEMCO Energy, Inc.'s credit outlook to "Stable" from "Negative."

Q. What other actions may SEMCO Energy, Inc. pursue?

A. While SEMCO Energy, Inc. has not announced any further specific plans; it continues to evaluate opportunities as they occur. For example, in April 2006, SEMCO Energy, Inc. issued $4.6 million of Common Stock and paid cash, to retire $10.2 million of its Convertible Preferred Stock. Although this is a smaller transaction than the others I described earlier in my testimony, it is indicative of SEMCO Energy, Inc.'s commitment to improving its finances and capital structure.

Q. Have these improvements in SEMCO Energy, Inc.'s financial situation benefited SEMCO Gas and its customers?

A. Yes. Aside from the point I made earlier about coming closer to the industry average capital structure used by the MPSC to set rates, suppliers of natural gas to SEMCO Gas have recognized the improvement in SEMCO Energy, Inc.'s financial situation. As a result, they have substantially increased credit extended to SEMCO Gas for natural gas purchases and shown an increased willingness to bid on the Company's gas supply requirements. Early in 2005, the Company had modest credit with its suppliers, amounting to approximately $10 million. By the second quarter of 2006, supplier credit had increased to approximately $80 million. Over the same period, the Company experienced much more interest and competition in the bids received for gas supply requirements, including both existing and new suppliers. Customers have benefited from both developments.

Q. Please continue.

A. I should add that the Commission's authorizing timely increases in the Company's Gas Cost Recovery ("GCR") rate during the run-up in natural gas prices beginning in mid-2005 also contributed, in my view, to the willingness of suppliers to extend credit to the Company and help satisfy the Company's gas purchase requirements.

Q. How do equity analysts in the investment community view SEMCO Energy, Inc.?

A. My judgment is that equity analysts view SEMCO Energy, Inc. as in the midst of a restructuring and what is often termed a "turnaround." Since it represents approximately two-thirds of SEMCO Energy, Inc.'s gas distribution business, they view SEMCO Gas as an important part of SEMCO Energy, Inc.'s future. That means, of course, that analysts are keenly interested in the way in which SEMCO Gas is regulated by the Commission in Michigan.

Q. Please continue.

A. Here is a lengthy quotation from Credit Suisse First Boston analyst Carl Kirst that illustrates the basis for my view. He notes in his research report dated August 31, 2005: "SEMCO is a redefined small-cap natural gas utility at the tail end of a multiyear restructuring process. Key to understanding SEMCO's valuation is the significant reduction in business risk that has occurred over the last 6-18 months. Consider the following.

New management. SEMCO has a completely new executive team, a necessary step to rebuilding investor confidence. Over the last 18 months, new management has delivered concrete results, placing SEMCO on a glide path back to stable earnings and, we believe, ultimately, an investment-grade rating.

Healthier balance sheet. At year-end 2002, [SEMCO]'s total debt to capital was 85%. After a recently completed $30 million common equity offering in August, SEMCO has a 2Q05 pro forma total debt to capital under 65%.

Further, credit metrics are now on a strengthening trend after several years of deterioration.

Returned to regulatory roots. With the sale of its losing E&C operations in 2004 and the winding down of its external IT business in 2Q05, SEMCO has returned to being a plain-vanilla gas utility. Management is committed to maintaining this focus, seeking to grow only as a regulated transporter and provider of natural gas.

Achieving regulatory stability and rate certainty. In the first half of 2005, [SEMCO] received positive decisions in each of its three regulatory jurisdictions."

Q. Are there other examples you wish to cite?

A. Yes. A.G. Edwards analyst Daniel M. Fidell notes in the Gas Utilities Quarterly Review dated April 6, 2006: "We are encouraged by the recent progress made by [SEMCO] and believe it is currently in the latter stages of turnaround efforts, with an identity shifting from troubled concern to that of a pure but leveraged distributor slowly strengthening its balance sheet over time as well as a potential takeover play."

Q. Please continue.

A. To my way of thinking, the investment community has recognized the progress that SEMCO Energy, Inc. has made in improving its finances and returning its focus to the gas distribution business. As SEMCO Energy,

Inc. has focused on its gas distribution business, regulation in Michigan and Alaska becomes a natural concern for the investment community.

Q. Have equity analysts addressed the issue of regulation in a way that bears on the Company's proposals in this case?

A. Yes. My view is that investment analysts are interested in regulatory mechanisms that provide greater certainty of earnings and cash flow. In fact, analysts favor gas distribution companies that have regulatory mechanisms that provide greater certainty of earnings and cash flow and penalize those companies that do not have such mechanisms. The A.G. Edwards Gas Utilities Quarterly Review dated April 6, 2006, notes: "We continue to favor gas distributors that have regulatory provisions to protect against abnormally warm weather and decreasing gas use." This article goes on to say: "We have been impressed with the willingness of regulators to consider weather normalization riders, performance-based rate freezes, bad-debt trackers and conservation decoupling mechanisms without forcing gas utilities to undergo base rate cases that are expensive and put gas utilities in a bad public light." Mr. Fairchild discusses the topic of regulatory mechanisms that provide greater certainty in detail in developing the Company's proposed rate of return in this case.

Q. Please summarize.

A. SEMCO Energy, Inc. is in the midst of a financial turnaround and is taking significant steps to improve its finances. The rate design changes that are

proposed elsewhere in this filing are another key element in that turnaround effort. In general terms, Commission adoption of those proposals would be important in the investment community's evaluation of SEMCO Energy, Inc. As the Commission knows, SEMCO Gas is dependent on SEMCO Energy, Inc.'s ability to access capital markets on reasonable terms to fund the Company's MPSC Division operations and capital investments.

In the next section of my testimony, I explain why, aside from investment community perceptions and the effects of those perceptions on SEMCO Energy, Inc. and SEMCO Gas, Commission adoption of the proposals in the case is important, because the proposals address particular problems currently affecting SEMCO Gas.

Factors Affecting SEMCO Gas's Results

(1) MPSC Division Earned v. Allowed Returns

Q. What has occurred since the Company's last rate case was decided by the Commission in March 2005 to bring the Company back before the Commission seeking additional rate relief and changes in rate design?

A. In general terms, even with the rate relief authorized by the Commission in March 2005, the Company's MPSC Division earnings are substantially below Commission-authorized levels, primarily because of decreases in use per customer and increases in the costs of serving customers. In addition, higher and more volatile natural gas prices have exposed

significant weaknesses in the Company's current rate design, including what I view as a serious problem with relying on a volumetric distribution charge to recoup a portion of the Company's costs of providing service to residential customers. Whenever I talk about the costs of providing service, I also have in mind the Company's earning a reasonable return on the investments made to serve those customers. The truth is that the Company has not realized the rate increase authorized by the Commission in March 2005.

Q. Please continue.

A. In Case No. U-14338, the Commission approved a settlement in which the Company was authorized to earn an 11% return on equity. As shown on Exhibit A-12, Schedule 4, however, in 2003, 2004 and 2005, the Company's actual MPSC Division return on equity has been 8.5%, 6.23% and 6.43% respectively. To me, this result reflects the impact of two problems; the Company's allowed revenue requirement is not being recouped from MPSC Division customers and use of historical consumption patterns as a basis for recovering the fixed costs of service in a period of rising commodity prices does not work.

Q. Is there another way to view this situation?

A. Yes, despite base rate increases, SEMCO Gas's customers are actually paying less for gas service, on a per customer basis, not including the cost of natural gas, than they did ten years ago. In 1995, SEMCO Gas

received $277.15 on average from each residential customer. In 2005, that amount was $268.30.

Q. How is that possible?

A. Though the Company has been granted base rate increases, the rate increases have been more than offset by the reduction in usage over this period – which reduced the Company's collection of distribution charge revenues. I discuss the reduction in usage in more detail after I address the increased costs of providing service to the Company's MPSC Division customers.

(2) Increased Costs of Providing Service to MPSC Division Customers

Q. Please discuss the trend in the Company's costs of providing service to MPSC Division customers.

A. Other witnesses in this case detail the changes in the Company's costs of providing service to its MPSC Division customers since the Company's last general rate proceeding (which was based on a 2003 historic test year). From my perspective, I am aware that the Company's costs continue to increase substantially each year, despite (i) the fact the SEMCO Gas is generally in the top quartile in terms of efficiency compared to other gas distribution companies, and (ii) efforts by SEMCO Gas personnel to control those cost increases. I discuss the Company's relative efficiency later in my testimony.

(3) Rate Design Issues – Volumetric Distribution Charge

Q. Please discuss the Company's current rate design.

A. Aside from cost pressures being experienced by the Company, it is apparent to me that the Company's reliance on a volumetric distribution charge to recoup roughly half of its residential revenue requirement is a main reason why earned returns continue to be substantially below Commission-authorized levels and, in effect, SEMCO Gas never realized the additional revenues granted by the Commission in March 2005.

Q. Does that mean that the parties to the Company's last case and the Commission made a mistake in deciding SEMCO Gas's last general rate case?

A. No. To my way of thinking, this is one of those issues that is not readily apparent until there is an event that causes people to focus on the issue.

Q. Was there such an event after the Company's last general rate case was decided?

A. Yes. As the Commission is aware, the market price for natural gas rose significantly beginning in mid-2005, reflecting (i) the effects of hurricane-related damage to gas producing and processing facilities in the Gulf Coast, and (ii) what I view as a longer-term natural gas supply-demand imbalance. In my view, the significant rise in natural gas prices, which was passed along to MPSC Division customers in higher GCR charges, has highlighted and accelerated trends that, across the U. S., the gas

distribution business has been experiencing for a number of years. Mr. Alger and other witnesses describe this trend in Company's service territory in detail in their testimony in this case. In sum, the demand that the Company experiences on a per customer basis has been declining substantially for some period of time. The price run-up beginning in mid-2005, coupled with the Company's (and MPSC's) advice that customers conserve natural gas to keep their bills for service at manageable levels, has accelerated what is often termed "demand destruction," on a per customer basis. Mr. Alger explains in detail in his testimony why customer growth of the sort the Company has experienced in the MPSC Division has been insufficient to overcome this substantial and continuing use per customer decline.

Q. How does this "demand destruction" impede the Company's ability to recoup its costs and earn its authorized rate of return?

A. Demand destruction impedes the Company's ability to recoup its costs and earn its authorized return because: (i) roughly half of the Company's revenue requirement is recovered in a volumetric distribution charge; and (ii) the estimated volumes used by the Commission to set that volumetric distribution charge are too high compared to the volumes the Company actually experiences in the rate effective year. In other words, the revenue requirement set by the Commission anticipates that the Company will collect a given revenue stream based on historic consumption

averages. Those historic averages are not, it turns out, reasonably representative of conditions in the rate effective year.

Q. Explain in more detail why, in your view, relying on these historic consumption averages is a problem.

A. As I said, the problem is that these averages do not reflect the Company's actual consumption experience. The use of historic consumption averages fails to take into account the significant decline in consumption brought about by conservation and efficiency advancements, such as improvements in building methodologies and appliances. Those averages also do not reflect recent apparent customer reactions to higher natural gas prices – customers "dial down" their thermostats to conserve energy and control their monthly costs of natural gas service. In addition, as Mr. Alger discusses in his testimony, these averages reflect what the Company believes is an inappropriate way in which to "weather-normalize" these consumption figures.

Q. What is the consequence to the Company of the use of these historic averages to establish the volumetric distribution rate charged by the Company?

A. The effect of using these historic averages to set the Company's volumetric distribution rates is that the Company does not realize sufficient distribution charge revenues when, in reality, customers do not consume that amount of natural gas.

Q. Do you have anything to add to your testimony on this topic?

A. Yes. So far, I have described why the Company's current rate design does not, in my view, give the Company a fair opportunity to recoup its costs of providing service to MPSC Division customers, including its Commission-authorized return. In essence, in view of the substantial and continuing decline in use per customer being experienced by the Company, continuing to use a volumetric distribution charge to collect a portion of the Company's revenues is problematic.

There are other reasons, however, for changing the current residential rate design to the fixed monthly service charge rate design proposed in this filing by the Company. Other Company witnesses discuss these reasons in detail. From my perspective, in the current environment of higher and more volatile gas prices, it is particularly appropriate for the Commission to adopt a "pro-conservation" residential rate design. To me, a key benefit of the Company's proposed residential rate design is that it aligns Company and customer interests with respect to conservation. With such alignment, my view is that the chances are substantially improved that customers will conserve, conservation will influence long-term demand, and changes in demand will affect prices. In fact, as other witnesses in this case discuss in detail, to reflect the alignment that comes from the residential rate design improvement proposed by the Company, SEMCO Gas proposes that the Commission

fund in rates "This Cold House", a conservation and efficiency program for residential customers, and Company participation in the Low Income Energy Efficiency Fund.

Q. Is the Company's residential rate design proposal dependent on natural gas prices being higher and more volatile than in the past?

A. No, the proposed residential rate design makes sense independent of natural gas price activity. However, the Company believes that prices are likely to remain at higher levels and demonstrate continued volatility. This view is premised, in part, on a belief that there is a longer-term supply-demand imbalance, as a result of the use of substantial amounts of natural gas to generate electricity and governmental policies that keep substantial natural gas reserves from being brought to market.

If it turns out that the Company is (i) wrong about natural gas prices remaining higher and more volatile than in the past, and (ii) wrong in thinking that per customer usage will continue to decline and thus continue to be an inappropriate billing determinant for setting rates, MPSC Division customers would not be harmed by Commission adoption of the Company's proposed fixed monthly service charge rate design for residential customers. In fact, the Company would be harmed, in the sense that it will have given up the added revenues that would be produced when a volumetric distribution charge is applied to higher consumption levels.

(4) Rate Design Issues – LAUF Gas Costs

Q. Are there other ratemaking conventions currently employed by the Commission that you wish to discuss?

A. Yes. I will discuss the Commission's current ratemaking convention for determining the amount included in SEMCO Gas's revenue requirement for Lost and Unaccounted-for ("LAUF") gas costs and Uncollectible expense. Other witnesses discuss in detail the Company's proposals for changing these conventions. My testimony is intended to put these proposals in context.

Q. What are LAUF gas costs and what is the rate design issue identified by the Company?

A. LAUF gas represents differences between the sum of the components of natural gas supply and the sum of components of natural gas disposition. These differences may be due to quantities of natural gas lost through leaks, because of damage to the Company's system causing an escape of gas, or to the effects of data reporting problems and errors. Reporting problems include differences due to the net result of conversions of flow data metered at varying temperatures and pressures and converted to a standard temperature and pressure, the effect of variations in Company accounting and billing practices; differences between billing cycle and calendar-period timeframes; and imbalances resulting from the merger of data reporting systems that vary in scope, format, definitions, and type of

respondents. Stated simply, there always is a difference between the amount of natural gas any local distribution company purchases for delivery to its customers and the amount of natural gas delivered to customers at their meters.

Q. How well does SEMCO Gas manage LAUF gas?

A. SEMCO Gas minimizes LAUF gas very effectively. Over the past five years, the percentage of gas lost on the Company's system was: 1.59% in 2001; 1.06% in 2002; 0.59% in 2003; 0.97% in 2004; and 0.95% in 2005. By comparison, the average LAUF gas figure reported by the American Gas Association ("AGA") in its most recent available data was 1.28% for 2003.

Q. What causes changes in this cost of service item, and how does that affect the Company?

A. While the percentages of LAUF gas volumes are in a consistent range, the cost to the Company of LAUF gas is not. In 2002, when the Company's LAUF gas percentage was 1.06%, the Company's LAUF gas costs were $1,919,000. In 2005, when the percentage was 0.95%, the cost to the Company was $3,958,000; or over two times the 2002 expense.

This comparison points out the dramatic impact that rising gas prices have on the Company's actual LAUF gas costs. In fact, while not as substantial a contributor to the Company's financial results as declining use per customer in 2005, increases in the market price of natural gas

increased the Company's LAUF gas costs substantially in 2005. That, in turn, reduced the Company's actual earned return, compared to its Commission-authorized return.

Q. What is the rate design issue identified by the Company with respect to LAUF gas costs?

A. The Commission's current rate design for this cost item estimates the Company's LAUF volumes based on an historic average. LAUF gas volumes are priced at the market price in effect at the time of the Company's base rate proceeding.

The fact of the matter is, however, that LAUF gas volumes change from period to period, and the market price of natural gas fluctuates constantly. In 2005, for instance, shortly after the Commission issued its order in the Company's last base rate case, the market price of natural gas increased substantially, with the result that the Company did not collect its actual LAUF gas costs. Ms. Gardiner provides the details of the impact of this price change in her testimony. Under the Commission's current ratemaking convention for this cost of service item, it is virtually certain that the LAUF gas costs actually experienced by the Company will never match the allowance for these costs included in base rates.

From an overall policy perspective, the Company believes that the Commission should put in place a ratemaking mechanism that ensures that cost incurrence and cost collection are matched for this cost of

service item. In other words, in my view, it is inappropriate for the Company's earnings to be hurt or helped by what are essentially market-driven changes in the costs associated with LAUF gas.

Q. Do you have additional comments to make on this subject?

A. Yes. In her testimony, Ms. Gardiner proposes what I view as two fairer ways to treat LAUF gas costs for ratemaking purposes. This testimony is supported by testimony from Mr. Warsinske, describing the accounting for LAUF gas costs, pointing out that LAUF gas costs are a "booked cost of gas," and detailing the further accounting that is done by the Company because of the current exclusion of LAUF gas costs from GCR recovery by tariff. Mr. Ketchum discusses how LAUF gas costs are recovered in other jurisdictions, noting that most jurisdictions recognize LAUF gas costs as a cost of gas recoverable in GCR-type mechanisms. To me, this is an area where the Commission should make a tariff change and effect a rate design improvement that will put Michigan in step with the rest of the country and demonstrate that Michigan regulation is reasonable and responsive to changing conditions.

(5) Rate Design Issues – Uncollectible Expense

Q. Please discuss the rate design issue the Company identifies with respect to Uncollectible expense.

A. Again, the main issue with the ratemaking treatment of Uncollectible expense is that, under the Commission's current rate design, the

Company does not recoup the full cost of this cost of service item in a rising gas price market. In a sense, as is the case with LAUF gas costs, that is the result of a kind of regulatory lag – the Company simply cannot file, and the Commission cannot process, a case fast enough to change base rates to reflect substantial, market-driven increases in the cost of natural gas that drive this expense. In addition, this expense item is affected by changes in the Commission's customer billing rules, including the MPSC's adoption of temporary emergency billing rules in reaction to the higher natural gas prices experienced beginning in mid-2005.

Q. Discuss the Company's Uncollectible expense experience.

A. The Company also manages this area very well. This is demonstrated by the "2005 Best Practices Benchmarking" report produced by the AGA. SEMCO's Uncollectible expense per customer was $5.89, compared to the average of $15.20 for the industry. Even with the slowdown in the Michigan economy and higher gas prices, the percentage of Company uncollectible accounts in 2002 was 0.334% of total sales, while the percentage has only risen to 0.409% at year-end 2005. Again, however, because of higher market prices for natural gas, the Company's expense has increased from $718,150 in 2002 to $1,587,080 in 2005.

In addition, as noted, this expense item is affected by actions taken by the Commission to change customer billing rules. For instance, as a response to the higher gas costs this winter, the Commission made

changes to those rules, including extending protection from shutoff to additional customers and stretching out due dates for bills for service. As Ms. Gardiner points out, SEMCO Gas does not question the Commission's judgment in making these changes. The fact of the matter, however, is that the Company will incur an estimated $617,000 in incremental costs associated with those rule changes in 2006 (see Mr. Forsyth's Exhibit A-9, Schedule C-15). As Mr. Forsyth points out in his testimony, moreover, additional proposed billing rule changes will impose substantial additional costs on the Company, and an adjustment to the Company's revenue requirement for that known and measurable change is appropriate.

Q. Has the Company proposed a different rate design for Uncollectible expense?

A. Yes. In her testimony, Ms. Gardiner describes the Company's proposal for an annual "true-up" of this expense. Again, from my perspective, the Company's proposal is a reasonable response to the problem of Uncollectible expense varying with the market price of natural gas and changes in the MPSC's customer billing rules.

SEMCO Gas's Relative Efficiency; Comparison to Other Michigan Utilities

Q. You have stated that SEMCO Gas manages its LAUF gas costs and Uncollectible expense well compared to industry peers. In your view, does SEMCO Gas operate efficiently compared to others in the industry?

A. Yes. . Based on the AGA "2005 Best Practices Benchmarking" report, which utilizes 2004 data for each company, SEMCO Gas ranks in the first quartile for the majority of the operating metrics. For example, when comparing SEMCO Gas to other companies in the industry on distribution expense, which relates to all of the direct costs associated with maintaining a distribution system, the Company ranks in the first quartile on (i) distribution operations and maintenance ("O&M") costs per customer, (ii) distribution O&M costs per mile of main, (iii) distribution O&M costs per dollar of plant, and (iv) distribution O&M costs per Mcf sales. (See "2005 Best Practices Benchmarking", Exhibit A-12, Schedule 5). It is worth highlighting that SEMCO Gas's distribution O&M costs per customer of $31.58 was approximately 50% of the industry's average costs per customer of $63.04. There are other metrics in the AGA report that demonstrate the Company's operational efficiency as compared to other companies in the industry. For example, SEMCO Gas's Administrative and General expenses per customer, while not in the first quartile, was over $16.00 less than the industry's average cost per customer. SEMCO Gas's call center expense per customer was over

$7.00 less than the average cost per customer for the industry. Additionally, the customer accounts expense per customer was $19.68 compared to the industry median of $38.80.

Q. Please continue.

A. There are two additional metrics in the report that I would like to highlight. SEMCO Gas's meter reading expense per customer stands out as a prime example of the Company's embracing technology to provide better service to our customers at a lower cost. The Company's cost of $1.72 per customer for metering reading is over three times lower than the median meter reading cost per customer of $5.79, as reported in the AGA data. The Company's customers per employee statistic of 797 is 125 more customers served per employee than the industry median of 672, and 282 more customers served per employee than the average of the two largest gas distribution companies in the state of Michigan (DTE's MichCon and Consumers Energy).

Q. How does SEMCO Gas compare to other utilities in Michigan?

A. SEMCO Gas serves 8% of the natural gas customers in Michigan. In contrast, Consumer's Energy serves 51% of those customers and Detroit Edison's Michigan Consolidated Gas Company ("DTE") serves 35% of the state's natural gas customers. (Consumer's Energy serves about 1.7 million natural gas customers and DTE serves about 1.1 million natural gas customers.) Viewed another way, Consumer's Energy and DTE

deliver 45% and 41%, respectively, of all of the gas delivered in Michigan. SEMCO Gas delivers 8% of the gas consumed in the state. In addition, it is worth noting that Consumer's Energy and DTE are combined gas and electric companies, with substantial electric operations; the information recited above does not include the electric businesses of these utilities.

Q. What are some of the other significant characteristics of the SEMCO Gas system compared to these other companies?

A. SEMCO Gas has two storage fields totaling approximately 3.6 BCF of on-system storage for its MPSC Division customers. On-system storage provides about 10 percent of the storage required to serve its customers on an annual basis. This relatively low percentage of on-system storage requires the Company to rely upon leased pipeline transportation and leased storage to meet customer needs. In contrast, Consumer's Energy and DTE have approximately 136.5 and 124.0 BCF of on-system storage, respectively.

In addition, SEMCO Gas is comprised of the former Southeastern Michigan Gas, Michigan Gas, Battle Creek Gas, and Peninsular Gas companies. The resulting geographically diverse gas system is a series of non-contiguous piping configurations. A consequence of this characteristic of the SEMCO Gas system is that the Company has limited flexibility in the choice of transportation providers and reduced ability to bargain for discounts on higher volume purchases. In contrast, Consumer's Energy

and DTE each have extensive networks of interconnected transmission and distribution main, which allow them to distribute gas more easily between their service areas.

Q. How does SEMCO Gas compare to Consumers Energy and DTE, from a financial perspective?

A. Using the data filed in the 2004 MPSC Annual Report, SEMCO Gas's MPSC Division reported gas operating revenue of approximately $307.1 million, while Consumers Energy and DTE reported gas operating revenue of approximately $1.98 billion and $1.37 billion, respectively. Consumers Energy also reported serving approximately 1.8 million electric customers with $2.5 billion in electric operating revenues. DTE reported serving approximately 2.1 million customers with $2.4 billion in electric operating revenues.

Q. Why did you include these comparisons to other Michigan utilities in your testimony?

A. My general purpose is to put the Company's filing in context, which, in my mind, includes making sure that the Commission has a clear picture of SEMCO Gas in mind when it is deciding the issues in this case. In addition, however, in this filing, the Company is proposing various rate design changes that differ significantly from prior Commission practice. As I noted earlier in my testimony, these changes are proposed mainly because of two items; namely, the Company's inability to absorb

regulatory lag as it relates to higher gas prices and other costs, and the substantial drop in customer usage due to customer conservation over time and price-driven increases in conservation.

As noted above, Michigan gas utilities are not all alike. Relative size and financial condition determine how a utility is affected by a particular MPSC ratemaking convention (such as how LAUF gas costs or Uncollectible expense are recovered in rates). Also, for example, because Consumers Energy and DTE are combination companies, with both electric and gas operations, adoption of a fixed monthly service charge rate design (as SEMCO Gas proposes be adopted for recouping its residential revenue requirement) may not be as appealing to them as it is to SEMCO Gas.

Here is one possible reason for that difference in viewpoint. The MPSC set up a Capacity Needs Forum, which is addressing electric capacity needs. In the Commission's report to the state legislature on February 1, 2006, the MPSC showed demand and energy needs growing at about 2% annually in the Lower Peninsula and about 1% annually in the Upper Peninsula. This increase in expected electric usage is different than the Company's experience with declining natural gas usage and slow customer growth. Thus, adopting a different rate design for SEMCO Gas may be justified by this difference in expected future consumption.

In sum, to my way of thinking, there are sufficient differentiating factors among the state's utilities to warrant the Commission's making rate design determinations for them on a case-by-case basis. In addition, as noted in Ms. Gardiner's testimony, the Company is willing to implement its proposed fixed monthly service charge rate design for residential customers on a pilot program basis, if the MPSC would prefer to take that approach.

SEMCO Gas's Capital Spending and Constraints

Q. Is there another topic you wish to address?

A. Yes. I wish to discuss the Company's capital spending and constraints on that spending, as background information for the Commission's consideration of the Company's Accelerated Replacement Program ("ARP") proposal for certain bare steel pipe and compressor replacement projects.

Q. Please describe the pattern of the Company's MPSC Division capital spending over the last three years.

A. Capital expenditure projects are categorized into essentially four types: (i) new plant, which relates primarily to customer growth; (ii) replacement plant, essentially relating to non-discretionary public improvement projects; (iii) special projects, which over the past three years have related to improvements in technology related to customer service and field services as well as required pressure reinforcement throughout the

system; and (iv) other projects, which relate to expenditures for structures and improvements, underground storage and tools and work equipment. Over the past three years the Company has spent, on average, $16 million per year on capital expenditures, with the largest percentage relating to replacement plant. Again, the replacement plant is essentially for non-discretionary public improvement projects, which are mandated by a municipality or the Department of Transportation.

Q. How does that capital spending program compare to spending by other local distribution companies and established capital spending benchmarks?

A. The Company compares very favorably on capital expenditures as compared to other companies in the industry on a per customer basis. Using the "2005 Best Practices Benchmarking" data provided by the AGA, the industry's capital expenditures per customer metric at $134.20 per customer was more than twice the Company's cost of $64.55 per customer. However, on capital expenditures per dollar of depreciation, the Company spent $1.78 compared to the industry average of $1.56. In other words, the Company is spending considerable more than its depreciation expense to maintain and improve its system. These metrics when taken together demonstrate that, while the Company has spent a substantial amount of money ($1.78 for each dollar of depreciation expense) to ensure its customers have a safe and reliable system, it

spends those capital dollars in a highly cost effective manner when viewed from a per customer basis.

Q. Why, from your viewpoint, should the Commission approve the ARP?

A. In view of the Company's (i) relatively small size and financial condition, (ii) its already substantial capital spending program, and (iii) the non-revenue producing nature of these needed projects, it would be an appropriate exercise of ratemaking discretion for the Commission to authorize the Company to collect the capital-related costs on these projects before they are placed in rate base. Other witnesses discuss the rationale for and mechanics of the Company's ARP proposal.

Q. Does this conclude your testimony?

A. Yes, it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	[e-file]
of natural gas in its MPSC Division and	)	
for other relief.	)	

TESTIMONY OF JOHN ALGER

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of John R. Alger
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is John R. Alger and my business address is 1411 Third Street, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position with that employer?

A. I am employed by SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), as Manager of Regulatory Affairs.

Q. What are your responsibilities as Manager of Regulatory Affairs?

A. I am responsible for regulatory matters pertaining to the jurisdiction of the Michigan Public Service Commission (the "MPSC" or the "Commission") and the Federal Energy Regulatory Commission ("FERC").

Q. Please summarize your academic background.

A. I graduated from Michigan State University in 1977 with a Bachelor of Arts Degree in Accounting and from Eastern Michigan University in 1981 with a Masters of Business Administration.

Q. Please summarize your employment and professional experience.

A. I joined Consumers Power Company in the Rates and Rate Research Department in 1977 and progressed through positions of increasing responsibility within that department. In July 1987, I accepted a position with Southeastern Michigan Gas Enterprises, SEMCO Energy, Inc.'s corporate predecessor, to assist in the acquisition of the gas properties of Michigan Power Company, subsequently renamed Michigan Gas Company ("MiGas"). In September 1987, I was promoted to Supervisor of Regulatory Affairs. I was subsequently appointed first to Secretary-Treasurer and later to Vice President of Regulatory Affairs and Gas Supply for MiGas. Over the years, through mergers and corporate restructuring, I have had responsibility for rates and regulatory activity and with either shared or sole responsibility for gas supply planning.

Q. Have you previously testified in any regulatory proceedings before the MPSC?

A. Yes. I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery ("GCR") plan and reconciliation proceedings, as well as other kinds of proceedings.

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

A. The purpose of my testimony is to describe the significant declining use per customer experienced by SEMCO Gas over the past ten years. I will also discuss (i) the expected impact of Commission adoption of a fixed monthly service charge rate design on the Company's customers who are senior citizens or in the low income category, (ii) the Company's proposal for Lost and Unaccounted-For ("LAUF") gas cost recovery, (iii) the Company's proposal for recovering Uncollectible expense, and (iv) the Company's ratemaking proposal for a pipe and compressor replacement program.

I will also present the historic and test year customers, volumes and revenues, including adjustments and weather normalization. I will also present the historic advertising expense classifications and prior MPSC disallowances, the cost of gas, the adjustments to the cost of gas stored underground, the adjustment for Company use and LAUF gas costs, the adjustment for changes in leases and other adjustments to the customers, volumes and revenue data necessary to make that data representative of conditions expected to exist in the rate effective year.

Q. Please identify the exhibits which you are sponsoring in this case.

A. I am sponsoring the following exhibits:

Exhibit A-11, Schedule F-5-1	Declining Use per Customer
Exhibit A-11, Schedule F-5-2	Projected 2007 Use per Customer
Exhibit A-11, Schedule F-5-3	Customer and Volume Changes
Exhibit A-11, Schedule F-5-4	Low Income & Senior Impact

Exhibit A-11, Schedule F-5-5	Implementation of a Fixed Residential Rate
Exhibit A-3, Schedule C-5	Advertising Classifications
Exhibit A-3, Schedule C-6	Prior Commission Disallowances
Exhibit A-6, Schedule F-1	Summary of Historical Year Revenues
Exhibit A-6, Schedule F-2	Historical Year Customers and Volumes
Exhibit A-6, Schedule F-3	Historical Year Operating Revenues
Exhibit A-8, Schedule B-10	2007 Cost of Gas
Exhibit A-8, Schedule B-11	Working Capital Adjustment for Gas Stored Underground
Exhibit A-9, Schedule C-5	Company Use and Lost and Un-Accounted-For Gas
Exhibit A-9, Schedule C-6	Changes in Lease Expenses
Exhibit A-11, Schedule F-2	Test Year Volumes, Customers and Adjustments
Exhibit A-11, Schedule F-2-1	Incremental Peninsular Gas Revenues
Exhibit A-11, Schedule F-2-2	Rate Reclassification of GS Customers
Exhibit A-11, Schedule F-2-3	Partial Year Rate Case Normalization
Exhibit A-11, Schedule F-2-4	Weather Normalization
Exhibit A-11, Schedule F-2-5	2005 Transportation Booked Revenues
Exhibit A-11, Schedule F-3	Test Year Revenues and Adjustments

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

A. Yes, they were.

<u>Fixed Service Charge Rate Design and Declining Use per Customer</u>

Q. As part of this rate case, SEMCO Gas is proposing that the Commission approve a fixed monthly service charge rate design for the Company's residential customer class, in which all of the revenue requirement associated with providing service to residential customers is proposed to be recovered through a fixed monthly service charge. Other SEMCO Gas witnesses have addressed the benefits of such a rate design. Do you have anything to add this discussion?

A. Yes, I do, as an introduction to my testimony on the issue of declining use per customer. In addition to the benefits discussed by other witnesses, including freeing the Company to promote conservation without harming itself financially and stabilizing a greater portion of customers bills throughout the year, adoption of a fixed monthly service charge rate design should help reduce, in my view, how often the Company requests a base rate increase, at least when such an increase would be driven by declining use per customer.

As Mr. Ketchum testifies, and my own experience confirms, traditional rate design has used a volumetric rate as a principal means of recovering utility revenue requirements. For example, the current SEMCO Gas MPSC Division Residential rates consist of a $9.50/month customer charge and a $1.2230/Mcf volumetric distribution charge, plus a volumetric GCR charge. The customer charge and non-GCR per unit volumetric distribution charge are intended to recover the Company's non-gas costs of providing residential service.

In fact, however, SEMCO Gas has rarely achieved the per customer volumes used to set the per unit volumetric distribution rate in its most recent rate cases, due to a steady reduction in the amount of gas use per customer. This has led to the Company's not earning its allowed rate of return, as other witnesses in this case explain.

Q. Please describe this decline.

A. To illustrate this historic decline in use per customer, I have prepared Exhibit A-11, Schedule F-5-1. On this graph, I have shown the Company's 30-year, weather-normalized, use per customer for the Residential Space Heating class for the full calendar years from 1996 through 2005. As the graph illustrates, use per Residential customer has fallen from 124 Mcf to 105 Mcf per year over this 10-year period.

Also plotted on this graph is the test year normalized and adjusted Mcf per customer quantities approved by the Commission in the Company's last three general rate cases, Case No. U-11220 (with a 1997 test year), Case No. U-13575 (with a 2003 test year), and Case No. U-14338 (with a 2005 test year). As shown on the graph, while the Company's achieved use per customer for the years 1997 and 2003 was approximately equal to the test year expectation, the volumes actually achieved in subsequent years continued to fall below the expected volumes used to set rates.

Although weather was relatively close to normal in 2005, the achieved volumes for 2005 never approached the approved normalized 2005 test year volumes. In fact, also plotted on the graph is the 30-year weather normalized Mcf per customer the Company achieved during the 12 months ended March 2006, just three months after the end of 2005, showing that, as compared to December 2005, use per customer has fallen to 100 Mcf/year.

Q. Please discuss the effect of the Commission's standardized 30-year, weather-normal used in deriving test year volumes.

A. In addition to the steady decline in use per customer, the Company's ability to achieve the volumes used by the Commission to set the Company's rates has been adversely affected by reliance on a 30-year weather normalization as part of the rate-setting process. As the Company has said in previous general rate cases (Case Nos. U-9323, U-11220 and U-13575), a 30-year weather normalization is not a good predictor of the

weather to be expected in the next several years. The average of the last 30 years of annual degree days is colder than any of the 10-, 15- or 20-year period averages, demonstrating that the 30-year average is not representative of recently experienced weather – or, to my way of thinking, the weather to be reasonably expected during the period the new rates decided upon in this case will be in effect. Using the 30-year year weather normalization in rate cases has generally overstated the test year volumes, which has compounded the declining use per customer problem being experienced by the Company.

Q. Please discuss Exhibit A-11, Schedule F-5-1 further.

A. It should be noted that (i) due to falling or stable national gas prices throughout most of the 1990's, and (ii) the Company's three year GCR freeze, between April 1999 and March 2002, most of SEMCO Gas's customers' total annual bills, including GCR charges, either declined or held steady between the period from 1996 to March 2002. Since the end of the GCR freeze period in March 2002, GCR costs for the Company's customers have more than tripled.

Standard economic theory, involving price elasticity, suggests that use per customer should have shown a lengthy plateau during the period 1996 through the spring of 2002, followed by a sharp recent decline in use, due to the rapidly rising gas costs and the customer conservation the would be expected to result from gas cost increases. Schedule F-5-1 tells a different story of a steady, albeit uneven, decline over the entire period. To me, this trend suggests that something other than the recent price increases is driving the reduction in use per customer. The most likely explanations of the steadily falling use per customer are the regular replacements of older, inefficient gas equipment with new higher efficiency equipment, newly installed insulation and windows, and replacement of older, less energy-efficient housing with modern, more energy-efficient

housing. These kinds of regular efficiency improvements appear to have led to a long term trend of reduced use per customer. When also coupled with the current higher cost of gas, this trend is not likely to end but, instead, will likely accelerate, as customers react to higher prices by making efficiency improvements and conserving energy. Based on what I see, I expect volumes to continue falling on a per customer basis.

Q. Please comment on how use per customer is reflected in the rate-setting process.

A. Under the Company's current rate design, volumes are a billing determinant for the Company's non-GCR volumetric rate. In essence, in setting the volumetric distribution rate, a certain level of use per customer is assumed. In other words, the volumetric rate is set based on the assumption that the Company's residential customers will each continue to use, on average, an historical, weather normalized, amount of natural gas. If that assumed usage is too high compared to what customers actually use, the revenues produced by the Company's non-GCR volumetric residential rate will be insufficient to recoup the Company's costs of providing service, including the cost of capital. That means that, in an extended period of declining use per customer, designing the Company's volumetric rate recovery on an assumed fixed volume of gas use per customer will likely produce a revenue shortfall, unless the assumed use per customer accurately reflects the Company's actual experience.

Q. What choices does the Commission have in addressing this issue?

A. Two alternatives come to mind. One solution is to change the billing determinant, from a volumetric measure to a customer measure, as the Company is proposing in this case. The other solution, if volumes are to continue to be used as a billing determinant for a volumetric distribution rate, is to ensure that the assumed use per customer used to develop that rate is low enough to capture the declining use per customer trend seen in the Company's data.

On Exhibit A-11, Schedule F-5-2, I have shown the Company's experienced monthly use per residential space heating customer from January 1996, through March 2006. These volumes have been normalized for 15-year normal weather, which, in my view, is a better predictor of future weather and thus per customer usage. I have also developed the projected use per residential customer for the year 2007, by calculating the slope of each individual month's data. By extending the trend of the use per customer by the slope, I have derived a projected 2007 use per customer of 95.4 Mcf. In my opinion, if the Commission chooses to stay with the current rate design for collecting the Company's revenue requirement, then the Commission should use an annual consumption figure of 95.4 Mcf per customer or less to set the Company's non-GCR volumetric residential distribution rate. In my view, use of such a consumption figure would result in the establishment of rates that are more likely to reflect conditions in the 2007 rate effective year.

Q. What would happen if the Commission used its traditional method to calculate use per customer in setting Company's non-GCR volumetric distribution rate?

A. If the Commission continues to use the current rate design and uses a per customer consumption figure above 95.4 Mcf per customer per year, the Company would very likely be required to seek successive rate increases, over short intervals, essentially chasing the declining use per customer trend downwards, in an effort to collect its costs of providing service, including its Commission-authorized return on investment. In my opinion, staying with the traditional approach in the current circumstances and prompting the filing of successive rate cases would likely result in an inefficient use of Company and Commission resources and impose unnecessary costs on customers. This is especially so, when the rate design proposal advocated by the Company eliminates usage as a billing determinant and thus solves the problem I have been discussing.

Q. Please discuss customer growth and its role in offsetting this trend of declining use per customer.

A. Please refer to my Exhibit A-11, Schedule F-5-3. I have again shown a graph of the period 1996 through 2005. On the left axis I have plotted the growth in the total number of customers served in each year. On the right axis I have plotted, in thousands of Mcf, the total volumes sold and transported for customers each year. As shown, the Company's total annual sales plus transportation volumes have held relatively steady over the last 10 years. This relatively level annual volume pattern has occurred, however, only as a result of annual growth in the number of residential customers of 2% or greater each year. In other words, without customer growth in the 2% range, the Company's total annual volumes would have declined in this period.

Also, I should note that every new customer requires the Company to make additional rate base investments and incur depreciation expense, incremental operating and maintenance expenses, and taxes. When the Company's revenue recovery is dependent on a volumetric distribution rate, new customer growth must provide the additional expected volumes for those new customers or the Company will be not able recoup its costs of providing service to those new customers, including its Commission-authorized return. In addition, by providing the appearance of long term stable volumes, the addition of new customers has masked the fact that volumes per customer have fallen steadily for years. The growth of new customers, however high the rate of growth may be, does not in any way mitigate the loss of volumes from all other customers where a volumetric rate is used to collect a portion of the Company's revenue requirement. In other words, the Company can not make up lost volumetric revenue requirements from falling volumes simply by adding new customers.

The Impact of a Fixed Service Charge Rate Design on the Company's Senior Citizens and Low Income Customers

Q. How would the use of a fixed service charge rate design impact Company customers who are senior citizens or qualify as low income?

A. The Company does not possess income or age data for each of its customers. Although census data is available which provides median incomes and percent of families below the poverty level, by community, throughout Michigan, SEMCO Gas does not serve every customer in every community; nor can a link be made between the census data and any specific customer's use of gas service.

What the Company does posses is a record of persons self-reporting their status as senior citizens and a record of customers who have qualified for various low income assistance programs. Using this data, along with the winter period use of all Residential Space Heating customers in 2005, I have produced Exhibit A-11, Schedule F-5-4.

Schedule F-5-4 shows graphs of the numbers of customers and the dispersion of their average winter time use, in increments of 200 Mcf, for known Senior Citizens, Low Income Customers, and Total Residential Customers. Each page of Schedule F-5-4 shows a different geographical division of the Company, and represents different population densities and different economic wealth, throughout the state. Please note that the vertical scale on the right shows the number of Seniors Citizens and Low Income Customers whose use fell within each usage range. The left hand scale shows the numbers of Total Residential Customers who fell within each range.

Although the number of Total Residential Customers is considerably higher than the numbers of Senior Citizens or Low Income Customers, as you would expect, when the two scales are relatively equalized, the usage patterns of these three groups, by proportion of customers, are nearly identical. What this means is that, for all geographical

areas served by the Company, regardless of local wealth or population density, the typical winter period use by Senior Citizens and Low Income Customers is nearly identical to the patterns and volumes of use of all residential customers. In other words, since the patterns of use for Senior Citizens and Low Income Customers are so similar to the pattern of the general population of Residential Customers, a fixed monthly service charge rate design would have no greater or lesser impact on these customers than on all Residential Customers in general. Further, the annual financial impact on most customers of the difference between a fixed monthly service charge and a volumetric rate will be small, relative to the commodity cost of gas, which will continue to be volumetrically based.

Implementation of a Fixed Residential Service Charge Rate Design

Q. What is the Company's current revenue collection pattern under volumetric residential distribution rates?

A. Under the Company's current Commission-approved rate design, volumetric distribution rates provide more than half of all non-GCR residential revenues. The Company's revenue from the volumetric portion of its rates is highly seasonal, with approximately 12.5% to 14.6% of annual revenue collected in each of the months of December, January, and February. In contrast, only about 4.5% to 5.0% of that revenue is collected each month from June through September.

Q. How does that seasonal pattern of revenue collection change if the Commission approves a fixed monthly service charge rate design?

A. A fixed monthly service charge for residential customers collects the Company's revenues by charging the same amount each month, on a levelized basis, so there would no longer be a seasonal pattern to the Company's base rate revenue collection.

Q. What does that change in the pattern of collecting revenues mean, from an implementation perspective?

A. Any transition to a fixed service charge rate design will have a significant impact on the Company's earnings in the calendar year of the transition, unless care is taken with respect to when the monthly fixed service charge is instituted or some other adjustment is made to ensure that the Company does not over- or under-collect its costs to provide service to customers. For instance, a transition to a fixed monthly service charge rate design in the month of April, after the Company has finished billing customers based on winter heating season volumes, would provide a windfall, in the form of higher summer revenues for the Company in that year. Similarly, a transition to a fixed monthly service charge rate design in October, after charging customers based on low summertime usage, would unfairly harm the Company, by denying it the revenues expected to be collected in the high volume months October through December.

Q. What is the Company's implementation proposal, if the Commission adopts the fixed monthly service charge rate design proposed by the Company?

A. The Company is proposing that the Commission adopt a transitional year credit or surcharge, based upon the month, during the calendar year, in which a fixed residential rate becomes effective. On Exhibit A-11, Schedule F-5-5, I have shown such a schedule of credits or surcharges per customer. To develop this schedule I have calculated, by month, the volumetric revenues the Company will have collected year-to-date through the calendar year of 2007, based upon the 105.3 Mcf average residential customer volumes for the adjusted test year and the current volumetric rate of $1.2230 per Mcf. I have contrasted this seasonal pattern against the cumulative monthly fixed amount of $1/12^{th}$ of the annual volumetric revenues as the year progresses. For any given month during the year in which the Commission would issue an order authorizing the Company to start

applying a new fixed monthly service charge rate design, the Company will have either over-collected or under-collected its expected calendar year-to-date volumetric revenues.

The list of surcharges or credits by month shown on this schedule is designed to keep both the customers and Company whole during the calendar year, as if the Company had billed its current volumetric rate all year long over an average customer annual use of 105.3 Mcf, per the test year adjusted volumes. For example, if the Commission's order approving a fixed monthly residential service charge rate design were to become effective in the month of May 2007, the Company would credit $3.61 per month to each residential bill, for each month from May 2007, through the month of December 2007.

Bill Presentment of the Company's Several True-up Proposals

Q. In this case, the Company is proposing several true-up or reconciliation mechanisms. How does the Company propose to display these various surcharges or credits on a customer's bill?

A. The Company is proposing that all of its proposed true-up refunds or surcharges be netted together as a single, separate line item on a customer's bill. The purpose of this style of bill presentment is to reduce the potential for customer confusion. As Ms. Gardiner's testimony states, the Company also plans to educate customers about the new rate design, including these true-up or reconciliation mechanisms, if it is approved by the Commission, and would expect to do so from time to time thereafter. These efforts also should make it easier for customers to understand how they are being billed for service from the Company.

Net Lost and Unaccounted-For Gas Costs

Q. What does the Company propose with regard to LAUF gas costs?

A. Other witnesses discuss the Company's proposals and the rationale for them. I will confine myself to explaining how the Company proposes that net LAUF gas costs be collected, from an implementation perspective.

The Company is proposing that the net amount of LAUF, Company Use and Gas in Kind be removed from base rates and, instead, be collected as a gas cost and reconciled through the GCR process. This approach, which is preferred by the Company, would require removing net LAUF gas costs from base rates and booking these costs to Cost of Gas Sold. To follow the Company's proposal, $4,534,155 would be removed from the revenue requirement in this case.

In future GCR plan cases, the dollar amount of net LAUF gas costs would be estimated based upon forecasted plan year volumes and future gas prices, the same as all gas cost requirements in GCR plans are estimated. Net LAUF gas costs would be included, along with all other GCR plan gas cost estimates, to derive the Company's initial filed GCR factor. Net LAUF gas costs, booked monthly to Cost of Gas Sold, would also become a reconciling item in future GCR Reconciliation cases.

Q. Is there another aspect of this proposed change to the treatment of LAUF gas costs that warrants Commission attention?

A. Yes. Currently, Gas Customer Choice ("GCC") customers, or their suppliers, do not provide Gas In Kind ("GIK") quantities of gas to the Company in the same manner as the large transportation customer classes do, since GCC base rates have included an allowance amount of LAUF gas costs. Removing LAUF gas costs from base rates would also require that GCC customers, or their suppliers, be billed the GIK percentage of gas, which would, in turn, be credited to the Cost of Gas Sold.

Q. If the Commission should choose not to include LAUF gas costs in Cost of Gas Sold or to remove LAUF gas costs from base rates, what does the Company propose?

A. In that case, the Company proposes, alternatively, that the Commission establish an annual true-up or reconciliation between the authorized base dollar amounts of net LAUF gas costs in this case and the actual cost of LAUF experienced by the Company.

For each year, coincident with the period of the GCR plan year, SEMCO Gas will determine and report to the MPSC, on or before June 30, the amount by which the expense for net LAUF either exceeded or was less than the amount determined to be just and reasonable in this case. The difference between the amount of LAUF expense allowed and the amount of actual expense experienced would establish a lump sum amount, which would be refunded to customers or for which customers would be surcharged, prospectively, from all customer classes. Collection of the surcharge or refund of the credit would begin with the September billing cycles for a period of 12 months. The amount to be collected from each customer class would be determined by allocating the total amount to be collected or refunded, in the same percentage as the annual reported sales volumes of the GCR year, by rate class. The amount to be collected from or refunded to each customer will be determined by dividing the class refund or surcharge amount by the number of customers in the class as of final billing period of the GCR year. The per customer amounts would then be divided by 12, and this amount would be consolidated with any other surcharges or credits on each customer's monthly bill. At the end of the August billing cycle each year, the surcharge or credit for the LAUF expense true-up for the prior GCR year would cease, and a newly calculated surcharge or credit would replace the prior year surcharge or credit beginning with the September billing cycles.

In the case where a partial month bill is issued to a customer, the surcharge would be prorated based on the number of days of the month that the customer received service.

The Company is proposing that any remaining LAUF gas cost true-up amount balance would not be rolled forward into the following year's calculation for collection or refund. Any such amounts should be de minimis, since the credit or surcharged amount is based on customer count, which varies little over time.

Uncollectible Expense True-up

Q. What does the Company propose with regard to Uncollectible expense?

A. Again, other witnesses discuss the Company's proposal and the rationale for the Uncollectible expense true-up. I will explain how the Company proposes that the Uncollectibles expense true-up be implemented annually.

For each calendar year, SEMCO Gas would determine and report to the MPSC, on or before March 31 of the subsequent year, the amount by which the Company's actual Uncollectible expense either exceeds or is less than the amount determined to be just and reasonable in this case. The difference between the amount of Uncollectible expense allowed in this case and the amount of actual Uncollectible expense would establish a lump sum amount, which would be refunded to customers or for which customers would be surcharged, prospectively, from all customer classes. The amount to be refunded or collected from each customer class would be determined by allocating the total amount to be refunded or collected in the same percentages as the Uncollectible expense is allocated to the various classes in the cost of service study used for the purposes of determining class cost responsibility in this case. The annual amount to be collected from or refunded to each customer class would be determined by dividing the

class refund or charge amount by the number of customers in the class as of the final billing period of the year during which the excess or deficiency in Uncollectible expense was determined. The annual per customer amounts determined above would be divided by 12 and be either included as a surcharge or credit on each customer's bill.

At the end of each year's May billing cycle, the surcharge or credit for Uncollectible expense true-up for the prior year would cease and the newly calculated surcharge or credit, as filed with the annual report to the Commission, would replace the prior year surcharge or credit. Again, this amount would be consolidated with any other surcharges or credits and be shown on a separate line on each customer's monthly bill. As with the LAUF gas cost true-up, the Company is proposing that the Uncollectibles expense true-up amount balance would not be rolled forward into the following year's collection or refund.

Conservation Program Implementation and Annual Report

Q. How does the Company propose to implement and annually report the amount of conservation program revenues and expenses?

A. The annual costs of the Company's conservation program and LIEEF participation would be determined in this case. The annual conservation program expenses would be recorded in a separate program fund and all program surcharge revenues would be booked against that fund. The Company expects to fully expend the dollars collected in the fund and that any balances in the fund, plus or minus, will be transitory. Any balance remaining in the fund at the end of a calendar year will be rolled forward into its conservation efforts in the following year

The conservation program, as proposed by the Company, is only available for residential customer participation, therefore, the conservation surcharge would be

applicable only to residential customers. The conservation surcharge would be a fixed monthly charge developed by dividing the approved annual program costs by the number of residential customers established in this case and dividing by 12. The surcharge would begin to be billed immediately upon Commission order.

Each calendar year, SEMCO Gas will report to the MPSC, on or before March 31 of the subsequent year, the amount of conservation program surcharge revenues that have been collected and the program costs that have been expended. Based upon on-going program experience, the Company may also submit, within this report, proposals for modifying the program, along with the expected cost and benefits of the new proposals. In the event that a substantial balance existed in the fund and the program was ended, the Company would refund that balance to customers.

Accelerated Pipe and Compressor Replacement Program

Q. How does the Company propose to develop the surcharges for the Accelerated Replacement Program ("ARP")?

A. The Company will track and record the capital expenditures each year associated with the ARP. The total annual capital expenditures will be multiplied by the capital cost rate of 16.57%, as discussed by Dr. Fairchild, to derive the annual capital costs. These annual costs will be off-set by the savings of annual leak repair costs as presented by Mr. Larsen. The resulting net capital cost is the amount to be collected from customers by the ARP surcharge. The surcharge amount to be collected from each customer class would be determined by allocating the total net capital cost amount in the same percentage as main investment is allocated in the cost of service study used for the purposes of determining class cost responsibility in this case. The amount to be collected from each customer would be determined by dividing the class

surcharge amount by the number of customers in the class as of the final billing period of the calendar year. The per-customer amounts so determined would be divided by 12 and a surcharge would be included on each customer's monthly bill. Collection of the calculated surcharge would begin with the June billing cycles each year.

Each year the surcharge would increase by the return calculated on the next additional year's investment in rate base associated with the replacement of unprotected steel facilities and compressors under the program. The surcharge for the replacement program would continue to be added to the customer's bill until these investments were included in the Company's rate base in a subsequent rate case.

In the case of a partial month bill being issued, the surcharge would be prorated based on the number of days of the month that the customer received service.

Q. How does the Company propose to annually report to the Commission the amount of Accelerated Pipe and Compressor Replacement Program ("APR") revenues and expenses?

A. Each calendar year, SEMCO Gas would report to the MPSC, on or before March 31 of the subsequent year, an accounting of the footage of unprotected steel main and compressors replaced under the program, and the amount expended on unprotected steel main and compressor replacement. The Company would also calculate and present the surcharge to be applied to customer's bills over the 12 months from June through May.

<u>Advertising Classifications</u>

Q. Please explain Exhibit A-3, Schedule C-5, Advertising Classifications.

A. This Schedule is part of the standard filing requirements. The purpose of Exhibit A-3, Schedule C-5, is to categorize the advertising expenses booked as utility expense during the 2005 historic year into those classifications that the Commission allows as business expenses and those that are typically disallowed.

Prior Commission Disallowances

Q. Please explain Exhibit A-3, Schedule C-6, Prior Commission Disallowances.

A. This Schedule is part of the standard filing requirements. Exhibit A-3, Schedule C-6, lists the dues for certain organizations paid by the Company during the 2005 historic year, which the Commission has in the past disallowed, in whole or in part, for ratemaking purposes.

Historic Year Customers, Volumes and Revenues

Q. Please explain Exhibit A-6, Schedules F-1, F-2 and F-3.

A. These three schedules, from the standard filing requirements, show a summary of historical 2005 year revenues, customers and volumes, and the historical 2005 year operating revenues, respectively. I have not shown the historic year split between the "sales" rates and "customer choice" since, for rate purposes, both types of service are billed at identical rates. Also, through 2005, there were no customer choice customers. These exhibits also include the seven-month average count of Peninsular Gas Company customers from May 2005-December 2005, as well as the seven-month total of Peninsular Gas customers' volumes and the seven-month Peninsular Gas revenues, as billed under the authorized Peninsular Gas rates.

Schedule F-1 shows the total revenue by billing rate class.

Schedule F-2 shows the historic customers and the historic "volumes." It should be noted that SEMCO Gas bills its sales customers on a volumetric basis ("Mcf") and bills its transportation customers on a decatherm basis ("Dth"). Although the two measures are roughly equivalent, they are not identical. The Total "volumes" shown are mixed figures of Mcf and Dth.

Schedule F-3 shows the historic revenues by component by rate. It should be noted that SEMCO Gas collects gas cost-related revenues from transportation customers such as balancing penalties and balancing fees, which are credited to the GCR.

Non-Revenue Related Plant Additions

Q. Please discuss the Company's Non-Revenue Related Plant Adjustment.

A. As discussed in Mr. Larsen's testimony and as developed on Exhibit A-8, Schedule B-5, non-revenue related plant additions are the sum of all the instances where the Company has constructed facilities for which there are no direct or incremental customer or revenue additions. When the Company constructs facilities for the purpose of adding incremental customers, there is a corresponding incremental amount of revenue and possibly customer Contributions In Aid of Construction ("CIAC"), which help off-set the cost of those facilities. In the case of non-revenue related plant additions, while these additions are necessary, there is no off-setting revenue or CIAC.

Q. Is it reasonable and prudent for the Company to add plant for which it derives no additional revenue?

A. Yes, it is. There are a number of additional plant facility requirements that do not add new customers or new load but which must be made.

Such facilities typically consist of projects undertaken to improve safety, reliability, or efficiency, such as rebuilding city gate stations, new mapping software for distribution systems, radio system upgrades, automatic meter reading projects, an observation well for Collins Field, and SCADA system replacement. Other capitalized plant costs which do not directly generate incremental revenue are costs which may be booked to these accounts (such as franchises, storage land, storage lines, storage (structures and improvements), storage (compressor station equipment), storage (meters and regulators), transmission lines, transmission line meters and regulators, distribution land and rights, distribution structures, main replacement, cathodic protection, distribution (compressor station equipment and compressed natural gas equipment), distribution (meter, regulator, and city gate stations), service replacements, meters, meter installations, regulators, other distribution equipment, general buildings, office furniture and equipment, computer equipment, tools, shop and garage equipment, power operated equipment, communication equipment, and general miscellaneous equipment). As an example, if a street gets torn up to move a water or sewer line, the Company may have to invest in plant in many of the categories listed above, to make changes in its facilities to accommodate the public works activity. The plant put in service under these kinds of circumstances is non-revenue producing, since no new customer load is derived from it.

For the purposes of this case, Mr. Larsen has calculated a five-year average of all the non-revenue related plant additions, in the same manner as proposed by the Commission Staff and approved by the Commission in its November 7, 2002 Order in the Consumers Energy's general rate case, MPSC Case No. U-13000. Mr. Fairchild has used the five-year average to calculate the plant additions for the years 2006 and 2007.

2007 Cost of Gas

Q. Please explain Exhibit A-8, Schedule B-10.

A. This exhibit shows a projection of the 2007 cost of gas. This projection was developed using the same gas supply optimization model used by the Company in its 2006-2007 GCR Plan Case No. U-14718, updated for known numbers of customers, volumes and weather through February 2006 and for NYMEX futures gas prices based on the five day average for April 17-April 21 2006. The 2007 Cost of Gas is used to determine the Company's cost of gas in storage adjustment to working capital requirements, and for pricing the test year Lost and Unaccounted-For Gas adjustment and Uncollectible expense.

Working Capital Adjustment for Gas Stored Underground

Q. Please explain Exhibit A-8, Schedule B-11, Working Capital Adjustment for Gas Stored Underground.

A. Exhibit A-8, Schedule B-11 shows the projected working capital impact of the increased cost of gas stored underground for the year of 2007 over the cost of gas stored underground in 2005. During the year 2005, SEMCO Gas had a 13-month average balance of gas stored underground of 7,685,291 Dth, Column (A), at a 13-month average cost of $52,876,900, Column (C). Column (D) shows the anticipated 2007 13-month average balance of gas in storage will be slightly less at 7,291,320 Dth. This 2007 13-month average is based on of the storage plan filed in the Company's 2006-2007 GCR plan U-14718 updated for known customers, volumes and weather through February 2006 and the five day average of the NYMEX from April 17, 2006 through April 21, 2006. The cost of the 2007 13-month average gas in

storage will be $64,326,177. Comparing the 2005 13-month average, with the 2007 projection, results in an increased annual average cost of $11,449,277. This increase is the result of the higher cost of gas in 2007 and represents an increased cost of working capital required to finance the increased storage costs. These higher purchase costs are a reflection of higher market prices.

Company Use and Lost and Unaccounted-For Gas

Q. Please explain Exhibit A-9, Schedule C-5, Company Use and Lost and Unaccounted-For Gas.

A. Page 1 of 2 shows the 2005 Company Use Gas percentage of 0.156% and the five-year average of the LAUF gas and total throughput, for the September through August fiscal years 2000-2001, 2001-2002, 2002-2003, 2003-2004 and 2004-2005 in Mcf. The resulting five-year average percentage of LAUF was 1.012%.

Page 2 of 2, Line 1, shows the adjusted and normalized Total Throughput Mcf for 2007. Line 2 shows the adjusted and normalized Transportation Dth for 2007. Line 4 shows the 2005 Company Use percentage to total throughput. Line 5 shows the five-year average percentage of LAUF gas to total throughput. Line 6 shows the sum of lines 4 and 5 for the total percentage of gas used for developing the Gas In Kind ("GIK") percentage which is 1.168%. The Company is proposing that the GIK percentage rate charged to transportation customers be changed from the current 1.12% to 1.17%. Line 8 shows the calculated Company Use for 2007 and Line 9 shows the calculated five-year average Mcf for the 2007 LAUF gas. Line 10 shows the calculated 2007 GIK Dth by applying the GIK percentage on line 6 to the 2007 transport Dth on line 2.

Line 12 shows the net sum of lines 8, 9 and 10 for the total 2007 Net Company Use and LAUF Mcf. These Mcfs are then priced out at the 2007 Cost of Gas. Lines 16, 17, and 18 show the actual 2005 Mcf amounts of Company Use, LAUF and GIK Dth which are totaled on line 20. Also on lines 16, 17 and 18 are the 2005 booked dollar amounts of Company Use, LAUF gas and GIK which are also totaled on line 20. Line 23 shows the 2005 net cost of Company Use, LAUF gas, and GIK subtracted from the 2007 net cost of Company Use, LAUF gas and GIK for a test year revenue deficiency adjustment of $1,079,092.

Changes in Lease Expenses

Q. Please explain Exhibit A-9, Schedule C-6, Changes in Lease Expenses.

A. Page 1 of 2, of this exhibit shows a list of changes in certain building lease expenses for the test year 2007. These amounts have changed significantly from the amounts booked in 2005 and thus warrant an adjustment.

As shown on the schedule, there are four separate and substantial changes in lease expenses. Line 1 shows a lease cost reduction for the Three Rivers lease. By reassignment of several employees to other existing work facilities, the Company was able to reduce its leased space requirements in Three Rivers. Line 2 shows a lease expense increase in the New Haven service area, where the Company is changing locations. The existing lease space had become too small to accommodate the Company's equipment storage requirements in what is the Company's most rapidly growing area. The additional space will also allow storage of emergency equipment in the New Haven area, for faster response, rather than at a more distant facility in Port Huron. Line 3 shows a lease expense increase in the Houghton area, where the Company is moving from its Dollar Bay leased facility to leased space in Houghton.

When the Company acquired the Peninsular Gas service territory, it did not acquire any of Peninsular Gas's existing buildings. The new facility is more centrally located within the Company's prior and expanded service area.

Line 4 shows the MPSC Division portion of allocated lease expense for the leased Information Technology building, for space used to consolidate Training Department personnel and to house the Disaster Recovery equipment. In the mid 1990's, the Company converted its Gratiot Road warehouse and workshop building to accommodate a training facility, including PC training. Upon the sale and closure of the Company's Lapeer Road Service Center in 2004, the Company also moved its Disaster Recovery computers and equipment into the Gratiot Road building. The Company has now moved both its Training Department and the Disaster Recovery equipment into 30% of the floor space at the Information Technology building and converted the old Gratiot Road warehouse back to its original purpose. The Information and Technology building has climate control and is specifically wired throughout for extensive computer interfacing. It is therefore more appropriate to house the complex of computers and equipment used in Disaster Recovery and for PC training than the old converted warehouse. Page 2 of 2 of Exhibit A-9, Schedule C-6 shows the total lease expense for the Information Technology building with a 30% square footage allocation to the Training Department. The Massachusetts formula is used to allocate the Training Department expense to MPSC Division jurisdictional expenses.

Test Year Customers, Volumes and Revenues

Q. Before you discuss the historic and adjusted customers, volumes and revenues, please discuss the acquisition of Peninsular Gas and how you have reflected it in the following schedules.

A. SEMCO Gas's MPSC jurisdictional service territory, which I sometimes refer to as the "MPSC Division," to distinguish it from the Peninsular Gas area or the combined Total of SEMCO Gas and Peninsular Gas, acquired the service territory and most facilities of Peninsular Gas effective June 1, 2005. Beginning with June 1, 2005, the Company recorded all Peninsular Gas's customer counts, volumes and revenues, billed at Peninsular Gas's authorized rates, combined into the MPSC Division's customers, volumes and revenues for most of its monthly and totalized 2005 reports. For the ease of comparing internal Company reports with the numbers I show in my exhibits, I have shown all of my booked numbers, starting in the left hand columns, as combined MPSC and Peninsular Gas numbers for the months June through December 2005. When I discuss adjustments and normalizations, which include Peninsular Gas, I have shown a separate Peninsular Gas adjustment for only the period January through May, before Peninsular Gas numbers were combined into Company reports.

Q. Please explain Exhibit A-11, Schedule F-2, Test Year Volumes, Customers and Adjustments.

A. This exhibit and its accompanying and supporting Schedules F-2-1, F-2-2, F-2-3, F-2-4 and F-2-5 show the volume and customer numbers from Reported 2005 to the Normalized and Adjusted 2007. These exhibits also include the seven month average count of Peninsular Gas customers from May 2005-December 2005, as well as the seven month total of Peninsular Gas customers' volumes and the seven month Peninsular Gas revenues, as billed under the authorized Peninsular Gas rates. Included in the adjustments between 2005 and 2007 are adjustments for : (i) annualizing the

Peninsular Gas customers, volumes for the months of January through May and to adjust the Peninsular Gas revenues from their authorized Peninsular gas rates to the 2005 MPSC rates, (ii) a GS Rate Reclassification of customers for GS customers on rates not appropriate for their usage level, (iii) a partial year rate case normalization for new rates implemented in April 2005 and (iv) the Weather Normalization for both the MPSC and Peninsula Gas volumes.

Q. Have you performed a fully projected test year of customers and volumes for 2007?

A. No, I have not. I have begun with reported 2005 volumes and average 2005 customers and developed the incremental adjustments to those.

Q. Please continue.

A. Lines 1 through 17 of Exhibit A-11, Schedule F-2, Column (A) show the Reported 2005 volumes. Lines 1 through 4 show the Mcf volumes for sales while lines 7 and 8 are technically stated in Dth for Aggregated Large Transportation customers served under GS-2 and GS-3 TR rates. Lines 9 through 15 show the Dth for Large Transportation. Line 17 shows a mixed total of Mcf and Dth for the total Company.

Q. Please discuss the Column (B) adjustment for Peninsular Gas

A. As discussed above, the Company took ownership of the Peninsular Gas assets and customers in June 2005 and all customers and volumes from that date forward were included in the first column. Column (B) normalizes for the inclusion of the months January through May, 2005, before Peninsular Gas was purchased.

Q. Please discuss the Column (C) rate reclassification you performed on the GS rate classes.

A. In the last rate case the break even point between rates GS-1 and GS-2 was set at 801 Mcf per year. The break even point between GS-2 and GS-3 was set at 2,517 annual Mcf. At this point there continues to be a considerable number of GS

customers on rates that are non-economic for their use level under these break even points. The GS rate reclassification shows the result of what this reclassification would mean in terms of numbers of customers, volumes and revenues.

The Company proposes that, upon issuance of the final order in this case, these customers be moved to the rate that is most advantageous to them. Further, the Company would include a message in a bill insert advising customers of the analysis and the rate adjustments the Company has made and telling them that they may contact the Company and chose any rate for which they qualify.

Q. Please continue with your description of Exhibit A-11, Schedule F-2.

A. Column (D) shows the weather normalization impact to normalize 2005 adjusted volumes for a 30-year average normal temperature. Since all other adjustments were performed on the basis of actual 2005 volumes, the weather normalization was performed last, on the net adjusted volumes.

Column (E) of Exhibit A-11, Schedule F-2 shows the 2007 volumes and customers as derived from 2005 booked numbers and adjustments.

Lines 26 through 39 of Exhibit A-11, Schedule F-2 show the corresponding customer adjustments for the Peninsular Gas and rate reclassification of the GS customers.

Q. Please explain Exhibit A-11, Schedule F-3.

A. Schedule F-3 shows the revenues associated the customers, volumes and adjustments from Schedule F-2. Like Schedule F-2, just described, Schedule F-3 begins with actual 2005 revenues by rate shown in Column (A).

Column (B) shows the revenue impact of the additional Peninsular Gas Customers and volumes for the January through May period, plus it includes the incremental impact of adjusting, for the entire 12 months, the Peninsular Gas

authorized rates to the rates approved in Case U-14338, effective March 31, 2005. Greater detail for this adjustment is shown on Exhibit A-11, Schedule F-2-1.

Column (C) shows the revenue impact the GS rate reclassification. Greater detail is shown on Exhibit A-11, Schedule F-2-2.

Column (D) shows the revenue impact of an adjustment to normalize the 2005 rate increase received by the Company, effective March 31, 2005 in Case No. U-14338. This adjustment shows the increased revenue the Company would have received had the rate increase been in effect for the entire year of 2005. Greater detail of this adjustment is shown on Exhibit A-11, Schedule F-2-3, in which the entire incremental change in rates was applied to the months of January through March and one half the incremental change was applied to April due to the proration of the increase that occurred that month during implementation.

Column (E) shows the revenue impact of the weather normalization adjustment. Greater detail of the adjustment is shown on Exhibit A-11, Schedule F-2-4.

Column (F) shows the fully adjusted revenue for 2007.

Q. Please explain Exhibit A-11, Schedule F-2-5.

A. When the Company books Large Transportation revenues each month, all revenues, including miscellaneous service fees, GCR Related balancing charges, Customer charges, Volumetric charges and Remote metering charges are all booked into a single account. All Company reports show these combined revenue figures as a single lump sum without regard to their actual classification. This makes it necessary for identifying the separate components and re-classifying these revenues to develop a schedule as I have shown on Exhibit A-11, Schedule F-2-5. Dr. Fairchild has made

test year adjustments to move both the GCR related revenues and the Miscellaneous Revenues into their proper classifications based upon this schedule.

Page 1 of 3 shows the separation of GCR related revenues. During the year 2005, a change in accounting took place such that beginning in May, GCR revenues began to be booked into a separate account so only such revenues from January through April were combined into the Transportation Revenues account. The far left column shows the total GCR revenues from January through April by rate class.

Page 2 of 3 shows the Miscellaneous Revenues separated by rate class and Page 3 of 3 shows the booked rate revenues by rate class.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF JIM LARSEN

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Q. Please state your full name and business address?

A. James C. Larsen, 1411 Third Street, Suite A, Port Huron, Michigan 48060.

Q. What is your title and by who are you employed?

A. My title is Manager of Engineering Services for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy Inc.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson University, located in Potsdam, NY, in May of 1989 with a Bachelor of Science Degree in Mechanical Engineering. In April of 1990, I graduated from Navy Nuclear Power School's Officer Program, located in Orlando, FL, as a civilian (I was employed at the time by General Electric Company). I currently hold a Professional Engineer's License from the State of Michigan.

I was employed by General Electric ("GE") (the GE business group that I worked for was later sold to Lockheed Martin) from 1987 to 1999. My primary assignment in this job was in Navy nuclear power plant operations at the Knolls Atomic Power Laboratory in West Milton, NY. From 1996 through 1999, I held the position of a Nuclear Plant Supervisor. I was the senior person on site responsible for the safe operation of a nuclear power plant. In addition to operations, my responsibilities also included supervising electrical and mechanical maintenance, including metering calibrations, piping system modifications, regulator repairs, heat exchanger maintenance, cathodic protection maintenance, and valve maintenance. In addition, I have attended numerous seminars and short courses relating to facility design, pipeline safety, gas distribution system operation, cathodic protection, large engine repair, business, and management.

My natural gas industry-related experience began in February 1999 when I was hired as a Transmission Engineer at SEMCO Gas and soon after was promoted to Supervisor of Transmission Engineering, in April 1999. I was later promoted to the Manager of Engineering position in April of 2000. The responsibilities of my positions at SEMCO Gas have included metering and regulation sizing, transmission pipeline project management, gate station design

and regulatory compliance for gate station capacity reviews and over-pressure protection reviews. I have also been responsible for storage field oversight, including inventory calculations, well and compressor permitting and well drilling. Other areas of responsibility have included environmental investigation and remediation projects, environmental permitting, gas piping computer flow analysis, remote telemetry unit (RTU) maintenance, cathodic protection maintenance, gas control dispatch, meter shop and Company radio system maintenance.

Q. Have you previously testified before the Michigan Public Service Commission (The "MPSC" or the "Commission")?

A. Yes, I filed testimony in Case Nos. U-13960, U-14402 and U-14718.

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

A. Currently, SEMCO Gas is presently facing the need to undertake several large non-revenue producing capital projects in the near future; namely, the replacement of certain aging steel mains and storage field compressors. My testimony is intended to explain why these projects are necessary and to introduce an Accelerated Replacement Program ("ARP") as a means to accomplish these projects in a way that gives the Company timely recovery of the capital-related costs for the expenditures on them. Ms. Gardiner, Mr. Alger, Mr. Fairchild, and Mr. Ketchum also testify on the ARP proposal.

The last section of my testimony will describe the categories of capital expenditures for SEMCO Gas and show the calculations used to determine the historical investment into Non-Revenue Producing Plant.

Q. How is your testimony organized?

A. My testimony is organized according to the following topics:

- Background Information on Steel Mains and Storage Field Compressors
- Replacement Strategy
- Accelerated Replacement Program Description
- Historical Non-Revenue Producing Plant

Q. Are you sponsoring any exhibits in this preceding?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my direct supervision:

Exhibit A-8, Schedule B-5 Non-Revenue Producing Plant Additions
Exhibit A-8, Schedule B-5-1 Accelerated Replacement Program

Background Information on Steel Mains and Storage Field Compressors

Q. What kinds of pipe have been installed as mains and other components in SEMCO Gas's distribution system?

A. The Company's distribution system is comprised of bare steel, coated steel and plastic pipe. "Bare steel" is, as the name suggests, steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. Both exterior coatings and cathodic protection are intended to inhibit corrosion. The use of bare steel was common until the 1950's and 1960's, when the industry began to realize that, despite its strength, bare steel was subject to corrosion. By 1970, the federal government had prohibited new use of bare steel for natural gas distribution system infrastructure.

Q. Why is corrosion of natural gas distribution system components a problem?

A. Corrosion weakens the steel pipe used in a natural gas distribution system, through rusting or pitting. This, in turn, weakens system components, making them more susceptible to damage from external forces, and sometimes results in the failure of these system components. System failures cause natural gas leaks and related hazards to Company personnel, customers, and members of the public and may interrupt service to customers.

Q. What did the industry do to combat the problem of corrosion in bare steel pipes?

A. All metals corrode as a result of a natural process. In that natural process, the steel main interacts chemically with its physical environment. Most commonly, moist soil (which creates an electrolyte) around the pipe can cause corrosion. Direct electric current flows from the metal surface into the electrolyte, as the metal ions leave the surface of the pipe, and corrosion takes place. The current flows in the electrolyte to the site where oxygen or water is being reduced. This chemical site is referred to as the cathode or cathodic site. As noted, in order to

combat corrosion, utilities began using coated steel instead of bare steel for mains. Unprotected coated steel ("UPCS" or "coated steel") refers to steel pipe with an exterior coating intended to electrically isolate the steel from the surrounding electrolytes in the soil.

Q. Did the use of UPCS solve the problem?

A. No. Despite these efforts to replace bare steel mains with UPCS, and even though UPCS was for a time an accepted industry standard for dealing with this issue, unprotected coated steel was found to corrode as well. For the period from the 1940's through the 1960's, however, UPCS was one of just a few alternative piping materials available to meet the public demand for service and, it was thought, deal with the corrosion problem.

Q. What material eventually replaced bare steel and coated steel pipe as the material used to construct natural gas distribution systems?

A. The replacement material was cathodically protected coated steel pipe.

Q. What is "cathodic protection"?

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion (i.e., rusting and pitting) by applying an electrical current to the pipe. Cathodic protection reduces corrosion by making that surface the cathode and another metal the anode of an electrochemical cell. A primary function of a coating on a cathodically protected pipe is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal. At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection. Any steel pipe, whether bare or coated, that isn't cathodically protected is considered "unprotected".

Q. Has the industry further improved the functionality of its piping since the introduction of cathodically protected steel?

A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, this material is more costly to purchase and install than the next generation pipe; namely, plastic.

Q. What are the benefits of plastic pipe?

A. Plastic pipe has proven to be appropriate for gas system distribution-level pressures. Plastic pipe has strength and flexibility, and, as a result, is generally resistant to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. Plastic does not corrode, and therefore does not require cathodic protection.

Q. Does plastic pipe have any drawbacks?

A. Yes. A significant drawback to plastic is its relative vulnerability to third party damage compared to cast iron or steel. As a result, excavators that do not dig by hand in the vicinity of plastic facilities are very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are more likely to be able to resist external impacts.

Q. Why are you concerned about corrosion leaks as compared to other types of leaks?

A. While other causes can create leaks (such as third party damage, outside forces (such as frost and settling), construction defects (damage to pipe during installation), or material defects (faulty manufacturing)), corrosion is the leading cause of leaks in the Company's Michigan gas distribution system. Although only about 5% of the Company's MPSC Division's main is unprotected steel, in 2005, there were 222 steel main corrosion leaks, which is 48% of all leaks repaired. In other words, in view of the fact that only a relatively small portion of the Company's system is constructed with this material, unprotected steel main accounts for a disproportionate share of corrosion-caused leaks.

Q. Will the corrosion of the unprotected steel stabilize or mature?

A. No. Corrosion leakage on unprotected steel does not slow down, and the rate of leakage will accelerate as the unprotected steel facilities continue to deteriorate as a result of the natural process I described earlier.

Q. Please describe the manner in which SEMCO Gas has been addressing the problem of replacing its unprotected steel facilities without an ARP.

A. SEMCO Gas routinely replaces and retires unprotected steel components in its distribution system, typically in conjunction with state or municipal public

improvement projects or when the number or severity of leaks requires the Company to take action. Normally, an analysis of the pipeline segment's historical leak rate and a number of other internally defined risk criteria are used to decide between replacement and repair for facilities that are not impacted by municipal public improvement projects. With public improvement projects, the Company typically replaces its facilities, because of the extensive changes being made in the public right-of-way.

Q. What benefits do you see in Commission adoption of SEMCO Gas's proposed ARP?

A. Under the ARP, SEMCO Gas will remove deteriorating portions of its system, and thus reduce leaks and related hazards and risks of service interruptions, in a more systematic way, on an accelerated timetable.

Q. Does the ARP, as proposed, cover other kinds of facilities?

A. Yes. In addition to the pipeline facilities I have been discussing, the ARP covers certain storage field compressors.

Q. What are storage field compressors used for?

A. SEMCO Gas has two natural gas storage field locations where natural gas is stored in underground formations. Compressors are used at each storage field to take the gas at normal pipeline pressures and raise the pressure high enough to be able to inject the gas into the underground formation. SEMCO Gas has five compressors; three are located at the Morton storage field, and two are located at the Collins storage field.

Q. What are the purposes or advantages of underground gas storage?

A. Underground gas storage is important to SEMCO Gas for balancing its Gas Cost Recovery ("GCR") customers' daily supply and demand, mitigating high winter gas prices and volatility, providing peak-day deliverability, providing a level supply reliability, and reducing pipeline transportation costs. Underground storage provides the Company with the flexibility to increase supply quickly, via storage withdrawals, during periods of colder-than-normal weather, thereby avoiding the procurement of incremental supply in the daily gas market when prices are typically high. Underground storage also provides the Company the

flexibility to take gas off its distribution system quickly, via injections into storage, during periods of warmer-than-normal weather, thereby allowing the Company to contract for a higher level of winter fixed priced supply and avoiding selling excess supply into the daily market when prices are typically low.

Underground storage is also a key component in meeting the Company's peak-day supply plan. For the 2006-2007 GCR period, the Company is planning on 21% of its peak-day supply to come from underground storage. If this storage were not available, the Company would have to rely on incremental supply purchases in the daily market, typically at high prices, which may or may not be available.

In addition, underground storage is a source of reliable supply. It provides the Company with a source of supply that is readily available for withdrawals, mitigating the risk of upstream supply disruptions (such as those experienced during the after effects of hurricanes, supply basin deliverability problems, and interstate and intrastate pipeline curtailments).

A majority of gas purchased by SEMCO Gas originates in either the Southern United States or Western Canada. Since interstate and intrastate pipelines only contain a limited amount of transportation capacity, they are usually in highest demand during the winter months. Hence, the cost of firm transportation capacity that would be available year round is considerably higher than seasonal or interruptible capacity. By purchasing gas during the off-peak period of summer and storing the gas, SEMCO Gas can reduce its demand charges that would otherwise have to be paid to pipelines to make additional transportation capacity available during the more expensive peak season. Additionally, because of the availability of storage, SEMCO Gas is able to buy gas during the summer, at a fixed price, when it is less expensive and put that gas into storage to mitigate higher cost purchases made during the winter.

Q. Explain the role of compressors in providing access to the Morton and Collins storage fields.

A. The compressors are normally used to inject natural gas from the pipelines into the underground storage formations. The compressors are necessary to fill the

underground storage, since pipeline pressure is normally below the storage field pressure. The compressors raise the pipeline pressure higher than the underground pressure and valves are operated to allow gas to flow underground. At the Morton and Collins storage fields, the compressors are not utilized when withdrawing gas from the formation. When the gas is required to be withdrawn from the field, the storage field valves are operated to divert gas through above ground regulators, which control the flow of gas into the distribution piping.

Q. What are the consequences of a compressor outage?

A. The most immediate consequence of a compressor outage is that SEMCO Gas would have less flexibility to meet the daily balancing requirements, since the Company would be unable to inject gas (at all or in sufficient quantities) into storage. Financial penalties are assessed if the daily balancing targets are missed beyond the pipeline's tariff allowance. Without available storage fields, customers would have to pay for substitute services, and these costs would be booked as costs of gas that would be charged to SEMCO Gas's GCR customers.

Q. Please describe the age and condition of SEMCO Gas's compressors?

A. SEMCO Gas's Collins storage field compressor engines were built in 1986 and 1987. The three Morton Field compressor engines were built in the 1950s and have already been refurbished once in the 1970s or early 1980s. All of SEMCO's compressor engines are 1,000 HP Waukesha internal combustion engines with reciprocating Worthington compressors. The compressors are normally operated year 'round, but have the most engine hours during the summer storage injection period. Since they are used for meeting daily gas nomination targets, the compressors have a large number of start and stop cycles, normally on a daily basis.

Q. Why do SEMCO Gas's compressors need replacement or refurbishing?

A. SEMCO Gas performs required maintenance on these compressors. Since the engines and compressors have a significant number of moving parts, however, the vibration and friction that occur during compressor operations cause wear and fatigue on compressor components. The frequent start and stop cycles also add thermal stresses, as the compressor components heat up and cool down. Over

time, this wear leads to component failures. SEMCO Gas is experiencing a significant amount of failures on the compressors. In 2005, there were 64 failures, compared to 17 in 2004. Although SEMCO Gas promptly corrects and repairs all failures, failures are expected to increase with age and continued normal compressor usage. Also, the Company is beginning to experience difficulty in obtaining certain replacement parts, due to the age and obsolescence of some of the compressors.

Replacement Strategy

Q. Describe SEMCO Gas's plans for replacing unprotected steel mains and services?

A. SEMCO's distribution system consists of a substantial amount of unprotected steel mains and services that are subject to corrosion. Approximately 40% of all SEMCO's distribution piping is steel. Approximately 12%, or 237 miles, of the steel pipe is unprotected and should be replaced, to address the risk of corrosion and leak-related risks. The Company's plan is to undertake this work on an accelerated basis under the ARP.

Q. What is prompting SEMCO Gas to submit the ARP proposal at this time?

A. In spite of a history of replacing unprotected steel mains as part of its normal process of making system investments, the Company is currently averaging approximately 400 corrosion leaks per year in the system. During 2005, SEMCO Gas retired 3.7 miles of bare steel pipe. At this rate, it would take approximately 60 years to replace the remaining unprotected steel on the Company's Michigan system. The ARP, as proposed, would allow the Company to accelerate the replacement of unprotected steel pipe and accomplish this work in approximately 15 years.

Q. What method of replacement is the most cost-effective?

A. In my view, the most cost-effective strategy for replacing these facilities is a project-based replacement strategy that will permit the Company to plan the work efficiently and systematically. This is the premise of the ARP. Aside from the regulatory aspects of the program, the underlying intent of the ARP is to deal with this problem comprehensively, by planning projects in advance, instead of

replacing short sections of piping in a reactive fashion (as I said earlier, typically as a result of leaks) or in connection with public works projects (the main objective of which is typically making needed road or other infrastructure repairs rather than upgrading the Company's system).

Q. How will the Company identify main replacement projects to be done under the ARP?

A. Under the ARP, the Company will replace all unprotected steel mains and other related facilities, referred to "Eligible Facilities," based on the needs driven by the distribution system, in accordance with the basic tenets of system engineering and planning. Replacement priorities will be determined based on the condition and age of the pipe; geographical proximity; the capacity needs of the area; and, expected growth in system demand requirements.

Q. How will the Company ensure that this work is done efficiently?

A. Efficiencies will be maximized and costs minimized by concentrating contractor resources. By identifying large segments of the Company's system that require attention (such as through leak rates and repair percentages), the Company will focus resources and complete full segment replacements and tie-ins in an orderly and cost-effective fashion.

Q. What materials will be used for the newly-installed mains?

A. The replacement mains and services will primarily be plastic pipe for systems with Maximum Allowable Operating Pressures of 60 psig or less. High pressure mains will be replaced with cathodically protected coated steel.

Q. Describe what tasks must be done when replacing unprotected steel segments?

A. These tasks include the replacement of unprotected steel mains and services as well as the installation of new tie-overs and relocation of affected meters and regulators. All risers, regulators, and meters will be moved outside of the customer premises, to reduce the pressure of the gas entering the premise and improve accessibility for Company personnel.

Q. Is cathodically protected steel also included as an Eligible Facility under the ARP?

A. No, as long as the pipe is sufficiently cathodically protected, it would not be an Eligible Facility under the ARP. SEMCO Gas does reclassify pipe on occasion, if a satisfactory level of cathodic protection cannot be maintained. In these cases, SEMCO Gas considers the coating on the pipe to be deteriorated enough for the pipe to be classified as bare, unprotected steel.

Q. How would you expect the ARP to affect leak repair experience?

A. The Company expects to reduce the level of corrosion leak repair-related operations and maintenance expenses as a result of the ARP. As shown in Exhibit A-8, Schedule B-5-1, Page 2, the number of corrosion leaks has been decreasing as the amount of steel main has decreased over the last 15 years. Although the general trend is a reduction in leaks, the number can fluctuate from year to year based on a number a factors, including frost stresses on the pipe and variability in corrosion patterns.

Q. How would leak survey frequencies change?

A. Bare steel pipe is required to be surveyed for leaks every 3 years. Protected steel and plastic pipe are only required to be surveyed every 5 years. As the bare steel is replaced, primarily with plastic pipe, the frequency of leak surveys for those sections of main will be reduced.

Q. Why are storage field compressor replacements included in the ARP?

A. SEMCO Gas also has an aging fleet of storage field compressors. The replacement or complete refurbishment of these compressors is a significant and unusual expense, and the Company faces the same financial and ratemaking considerations in making these expenditures as the Company does in replacing unprotected steel pipe. Other witnesses discuss these topics in their testimony in this case.

Q. Describe SEMCO Gas's plans for replacing storage field compressors?

A. SEMCO Gas plans to review the operating history of each compressor and replace the compressors sequentially over a 10-year period. SEMCO Gas would prioritize the compressor replacements based on age, condition and failure frequencies. SEMCO Gas would perform the replacements by purchasing new or reconditioned units and performing a direct replacement of the existing

compressors. SEMCO Gas would then either sell the old compressor for any residual salvage value or send it in to a repair facility to perform a complete overhaul. Due to extensive purchasing lead times on compressors and cycle times for overhauls, it is expected that one compressor could be replaced every two years.

Accelerated Replacement Program

Q. Describe the Accelerated Replacement Program SEMCO Gas is proposing in this proceeding?

A. SEMCO Gas requests that it be authorized to implement an Accelerated Replacement Program under which the Company will expense approximately $5 million per year, to accelerate replacement of steel mains that are not cathodically protected and aging storage field compressors. From time to time in this testimony, I refer to these projects as Eligible Facilities and their associated costs as Incremental Capital Investments.

Q. What qualifies as an Eligible Facility?

A. Eligible Facilities are proposed to include the costs of certain main replacement projects, including any related facilities (such as services, meters or regulators) that must be installed or replaced to enable the main replacement to become operational. Eligible Facilities may include investments in one or more of the following plant accounts: Distribution Mains, Services, Meters, Meter Installations, Regulators, Industrial Metering and Regulating Equipment, Storage Compressor Station Equipment, and related Storage Compressor Station Equipment.

For mains, the key criterion that makes an investment an Eligible Facility is that it has to be either an unprotected steel main or service or other related facility tied to an unprotected steel main. For compressors, what makes a compressor an Eligible Facility is that it is listed in this testimony as being included in the ARP.

Q. What does SEMCO Gas propose to do each year under the ARP?

A. SEMCO Gas is proposing to replace approximately 12 miles of unprotected steel pipe per year, for 15 years, under the ARP. This would be a pace equal to 4 times the historic pace of replacement. An overall projection of the ARP replacements and estimated costs are shown in Exhibit A-8, Schedule B-5-1, Page 1. This is a target mileage figure, and the exact annual mileage to be replaced will depend on specific project requirements. Additionally, as cathodically protected coated steel pipe ages, some of this pipe may also degrade to the point of being reclassified as bare, unprotected steel, and therefore become an Eligible Facility. The Company's annual ARP costs will be affected by factors such as the type of pavement, the type of soil, the density of other utility services in the area, the required traffic rerouting, and other construction project variables.

Q. How does SEMCO Gas propose to replace the compressors?

A. SEMCO Gas is proposing to replace or send out for overhaul one compressor every two years over the next 10 years. It is expected that the cost for each compressor replacement or rebuild will be between $1.5 and $3 million dollars, depending on market conditions and the salvage value or overhaul potential of the compressor. A nominal value of $1 million dollars per year was assumed for the projections, splitting the cost of each compressor upgrade between two consecutive years.

Q. How does the ARP account for any reduction in operations and maintenance ("O&M") costs as a result of the unprotected steel replacements?

A. As the amount of unprotected steel is reduced, the Company will experience some cost savings as a result of fewer leak repairs and reduced leak survey frequencies. This cost savings will be calculated based historical measures and included as an offset to the capital-related costs reimbursed under the ARP. The Company believes that this O&M offset is reasonable, in view of its request that the Commission authorize the recovery of ARP-related capital costs between general rate cases.

Q. Provide an example of how you would determine the cost savings for a reduction in O&M?

A. For 2005, the average steel pipe leak required 13.65 man-hours to repair. SEMCO Gas's 2005 labor rate was $78.38 per hour, resulting in an average cost of $1,070 to repair a steel pipe leak. As an example, if the number of leaks were reduced by 25 in a given year, there would be a corresponding Leak Savings Offset of $26,750. The offset from reduced leak surveys is expected to be minimal and was not included.

Q. Please explain how the Unprotected Steel Replacement costs are determined in Exhibit A-8, Schedule B-5-1, Page 1.

A. The first column is the Year (1) of the program. The second column is the estimated amount of Remaining Unprotected Steel (2) in SEMCO Gas's system. As expected, this amount is reduced each year of the program, until the amount reaches 0 after Year 15. The Annual Base (3) is the number of mile of unprotected steel pipe SEMCO Gas currently replaces in a 1-year period. The base number was determined using the number of miles replaced during the historical test year of 2005. The ARP Eligible Steel (4) is the estimated miles of unprotected steel that should be replaced each year to complete the program in the specified time period. Both the Annual Base (3) and ARP Eligible Steel (4) amounts are subtracted from the Remaining Unprotected Steel (2) each year to determine the following year's remaining Eligible Facilities, aside from the compressors. The fifth column is the estimated Cost per Mile (6) to replace unprotected pipe and related facilities. These costs were determined by using 2005 actual expenses and then adjusted for inflation. The sixth column is simply the fourth column multiplied by the fifth column, which obtains the total ARP Steel cost for the year.

Q. Please explain how the compressor replacement costs are determined?

A. The estimated costs for the compressor replacements are included in Column 7 of Exhibit A-8, Schedule B-5-1, Page 1. These costs estimate the value of $1 million dollars each year for 10 years, adjusted for inflation each year.

Q. Is the Company requesting that all ARP investments be automatically included in rate base and base rates adjusted appropriately each year?

A. No. The Company is proposing that it recover only ARP Capital Related Costs, until the next general rate proceedings, when these investments would become part of SEMCO Gas's rate base.

Q. How are the ARP Capital Related Costs determined?

A. As shown in Exhibit A-8, Schedule B-5-1, Page 1, column 8 is the total of the ARP Steel Costs (6) and the Compressor Replacement Costs (7). This is the Incremental Capital Investment for the year related to the program's Eligible Facilities. The Incremental Capital Investment (8) is then multiplied by the Capital Charge Rate, 16.57%, as determined in Mr. Fairchild's testimony, to determine the Capital Charge (9). This Capital Charge is then offset by the estimated O&M savings related to these projects, based on corrosion leak reductions. The Leak Savings Offset (10) was determined using costs and reductions from the 2005 historical year and adjusted for inflation. The Leak Savings Offset (10) is then subtracted from the Capital Charge (9) to obtain the total Capital Related Costs (11) for that year. Mr. Alger's testimony details the reporting and methods for collecting the Capital Related Costs via a surcharge. For 2007, the costs for the program are included as a known and measurable expense in this rate case, and as such, these costs would also offset the Capital Related Costs for that year.

Q. How will the Commission be able to assure itself that the Company's expenses associated with the ARP are reasonable?

A. SEMCO Gas proposes to recover only ARP costs that are reasonable in amount. Therefore, in the annual report discussed in Mr. Alger's testimony, SEMCO Gas will include a summary of the related construction projects completed in the prior year and a calculation of the Leak Savings Offset. The Commission will then have the opportunity to audit SEMCO Gas's ARP costs included in that particular ARP report before the surcharge takes effect. Because the filing with the Commission will be made after the conclusion of a construction program year, the Commission will have the opportunity to confirm that the replacements were prudently undertaken and the costs reasonably incurred. The report will also include a summary of the projects planned for the current program year, and the

Company would be willing to provide any information reasonably necessary to explain and justify the projects to the Commission. Again, the Company is only seeking recovery of the Capital Related Costs for the ARP between general rate cases. I also should repeat that ARP investments themselves would not be included in the Company's MPSC Division rate base until they were subject to review by the Commission in a general rate proceeding.

Q. Do you have anything further to add on this subject?

A. Yes. I view the ARP as a reasonable way to fund a substantial improvement in the way in which the Company is now able to deal with unprotected steel main corrosion and infrequent but necessary compressor system investments. To my way of thinking, Commission approval of the ARP will allow projects to be done that would otherwise be deferred in the normal capital budgeting process. That said, with this funding, SEMCO Gas would continue to conduct its construction projects, including those under the ARP, prudently, with the objective of doing this work efficiently and cost-effectively.

Historical Non-Revenue Producing Plant

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to describe the categories of capital expenditures for SEMCO Gas and how they are used to determine historical investment in Non-Revenue Producing Plant. This information is used by Mr. Fairchild in determining working capital projections. This portion of my testimony explains the mechanics of the separation between Non-Revenue Producing Plant and Revenue Producing Plant capital expenditures over the past five years, and details how the calculations were made.

Q. What are the major categories of SEMCO Gas's capital budget?

A. The major capital budget categories are New Customer Construction and Non-Revenue Producing Plant (includes system improvement projects and public improvement projects). Non-Revenue Producing Plant categories include routine and special projects that enhance, replace, or maintain SEMCO Gas's current

facilities. Revenue Producing Plant categories (New Customer Construction) include routine and special projects to add new customers.

Q. What are the components of the New Customer Construction category?

A. New Customer Construction includes new mains, new services, capital in aid of construction (CIAC – dollars contributed to the construction project by customers that offset the cost of new capital construction projects), meters, meter installations, regulators and industrial meter and regulator stands.

Q. How does SEMCO Gas separate the costs for New Customer Construction projects from other types of projects?

A. New mains, services, and the associated CIAC are gathered using separate accounts that are set up to capture costs for construction of these facilities. Labor, equipment, and materials utilized to construct new mains and services are charged to these accounts, which are totaled on the Construction Work in Progress ("CWIP") pages of SEMCO Gas's accounting records. Meter, meter installation, and regulator accounts are set up to capture new and replacement charges. A calculation is then performed to separate new meters, meter installations, and regulators from their replacement counterparts. The industrial meter and regulation account captures the expenses associated with these types of facilities for new industrial customers.

Q. What are the components of the Non-Revenue Producing Plant category?

A. The Non-Revenue Producing Plant category captures capital costs not associated with New Customer Construction. The components included are: franchises, storage land, storage lines, storage structures and improvements, storage compressor station equipment, storage meters and regulators, transmission lines, transmission line meters and regulators, distribution land and rights, distribution structures, main replacement, cathodic protection, distribution (compressor station equipment and compressed natural gas equipment), distribution (meter, regulator, and city gate stations), service replacements, meters, meter installations, regulators, other distribution equipment, general buildings, office furniture and equipment, computer equipment, tools, shop and garage equipment, power operated equipment, communication equipment, and general miscellaneous

equipment. Each of these components has a separate account number to which the charges for these types of projects are posted. As noted earlier, meters, meter installations and regulators are separated between new and replacement by calculations.

Q. What is the difference between the Routine and Special Projects subcategories?

A. Special Projects are typically large, periodic, short-term projects that are not typical year to year expenditures. For example, past special projects have included the Southern Energy (Mirant) and East China transmission lines and stations to serve individual power plants (single new customer projects that are very large scale). Other capital expenditure projects (Non-Revenue Producing Plant) include: rebuilding city gate stations, new software systems for mapping, customer information and SCADA and system improvements.

Q. Please explain Exhibit A-8, Schedule B-5, Non-Revenue Producing Plant Additions?

A. This three-page exhibit is comprised of a summary sheet outlining the five year average for Non-Revenue Producing Plant and two detail sheets explaining the specific expenditures for both Non-Revenue Producing Plant and New Customer Construction from 2001 through 2005. The expenditures are for the MPSC Division of SEMCO Gas. The total dollar amounts tie back to the CWIP figures from SEMCO Gas's accounting records for each of the years noted.

Q. Please explain New Customer Construction – Routine Work.

A. New Customer Construction (Routine Work) refers to the mains, services, and appurtenances required to serve new residential, commercial and industrial customers, but excludes large single services to power plants. Mains and CIAC information was taken directly from the CWIP accounting records. New mains projects include all routine projects where main is installed to serve new customers. The only other main installed to serve new customers is included in New Customer Construction – Special Projects, which currently includes the transmission lines and stations required to serve power plants.

New Services and New Services (CIAC) information was taken directly from the CWIP accounting records. New services include all services installed to serve

new customers where no previous service existed. Meters, Meter Installations and Regulators for New Customer Construction – Routine Work were calculated based upon the number of new services added and an approximate cost of the material and/or labor. For 2001, an approximate meter installation charge of $146 per new service and a meter/ERT cost of $100 were used, based on a 1998 cost study. A cost study was performed again in 2003 and the revised pricing was updated for 2002 and 2003. The same pricing used in 2003 was applied to 2004, as there have been no known significant changes in these costs for these years. The costs for meters, meter installations, and regulators were then multiplied by the number of new services added each year to yield the total values used for Routine Work - New Customer Construction components. All remaining amounts in the meter, meter installation, and regulator accounts were then allocated to the Routine Work – Non-Revenue producing plant components. Industrial M&R captures the expenditures to provide meter and regulator assemblies for new commercial and/or industrial customers. This information was taken directly from the CWIP pages from SEMCO Gas's accounting records for each year.

Q. Please explain New Customer Construction – Special Projects.

A. Approximately $1.2 million dollars was spent in 2001 on the Southern Energy project, that currently serves the Mirant Power Plant, and to begin the East China project for DTE East China, LLC. The East China 16" Transmission Line shows a negative balance in 2001, due to payment being received for the pipeline portion of the project. In 2002 and 2003, $1,761,779 and $4,642 were spent, respectively, primarily for the completion of the DTE East China M& R station and the Southern Energy project.

Q. Please explain Non-Revenue Producing Plant – Routine Work.

A. All of the account titles listed under "Non-Revenue Producing Plant – Routine Work" pertain to Non-Revenue producing projects. There are specific account numbers assigned to these categories that capture the associated charges. Exceptions include meters, meter installations, and regulators included new and replacement equipment and labor charges for these categories. To determine

replacement meters, meter installations, and regulators, the calculated costs for meters, meter installations, and regulators for new customers were deducted from the total amount in each account.

Q. Please explain Non-Revenue Producing Plant – Special Projects.

A. Specific account numbers were set up in SEMCO Gas's Property Accounting system to capture costs associated with non-routine Special Projects. Non-Revenue Producing Plant – Special Projects identifies larger scale projects associated with Non-Revenue producing technology initiatives or system improvements. Examples include automatic meter reading initiatives (ERTs), piping system improvements, gate station improvements and software system replacements.

Q. Does that conclude your direct testimony at this time?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **SEMCO ENERGY GAS COMPANY** for authority to redesign and increase its rates for the sale and transportation of natural gas in its MPSC Division and for other relief.	)))))))	Case No. U-14893

DIRECT TESTIMONY AND EXHIBIT OF JAMES VAN SICKLE

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony Of James Van Sickle
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is James A. Van Sickle. My business address is 1411 Third Street, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position with that employer?

A. My present position is Rates Analyst I in the Rates and Regulatory Department at SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc.

Q. What are your responsibilities as Rates Analyst I?

A. Under the supervision of the Manager of Regulatory Affairs, I have responsibility for participating in Michigan Public Service Commission ("MPSC" or "Commission") proceedings, including preparing exhibits and workpapers, writing testimony, submitting to cross-examination, and otherwise representing the Company before the MPSC. I am also responsible for the preparation and filing of MPSC case applications, communication of MPSC tariff changes and other regulatory assignments as needed. My additional responsibilities include monitoring and analyzing Federal Energy Regulatory Commission activity related to the Company's interests and researching regulatory topics that arise at the Company from time to time.

Q. Please summarize your academic background.

A. In 1981, I graduated from St. Clair County Community College with an Associates degree in Arts. In 1984, I graduated from Michigan State University with a Bachelor of Arts Humanities/Pre-Law degree. In 1990, I

received an Associates degree in Paralegal Studies from Mountain West Junior College.

Q. Please summarize your relevant employment and professional experience.

A. In 1997, I joined SEMCO Gas as a Marketing Analyst. While with the Marketing Department, I reviewed processes and developed and implemented procedural changes that streamlined several aspects of that department's activities. In 1999, I moved into the position of Manager of Process and Analysis with SEMCO Energy Ventures ("Ventures"), an unregulated subsidiary of SEMCO Energy, Inc. Under the direction of the president of Ventures, I gathered and prepared information for the construction and engineering companies, as well as the production facilities that were then held by Ventures. I then worked in the Training Department for SEMCO Gas, tracking documentation and developing various processes. I have been in the Rates and Regulatory Department since June 2004 and have been involved in data gathering and presentation, reporting, and various support roles.

Q. Have you previously filed testimony with the MPSC?

A. Yes, I filed testimony on behalf of SEMCO Gas in Case Nos. U-14338, U-14402, U-14718, and U-14726.

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

A. The purpose of my testimony is to discuss the 2005 Miscellaneous Fee Normalization and landlord agreement fees, and to present tariff sheets that reflect all of the Company's tariff-related proposals in this proceeding.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-11, Schedule F-3-1	Miscellaneous Fee Normalization
Exhibit A-11, Schedule F-3-2	Landlord Transfer Fee
Exhibit A-11, Schedule F-7	Summary of Proposed Tariff Changes
Exhibit A-11, Schedule F-8	Proposed Tariff Sheets

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

A. Yes they were.

Miscellaneous Fee Normalization

Q. Please describe Exhibit A-9, Schedule F-3-1.

A. This exhibit normalizes certain miscellaneous fees that were increased on March 31, 2005, after issuance of the Commission's Order in Case No. U-14338. The net number of items chargeable under the Company's schedule of fees for January, February and March are summarized for each of the following fees: Non-Sufficient Funds, Collection, Regular Turn On, and Seasonal Turn On. The number of items for each fee was then multiplied by the incremental difference between the existing older fees and the newly approved fees, the sum of which is $123,974. This sum represents additional revenue SEMCO Gas would have realized had the rates authorized in Case No. U-14338 been in effect for the entire 12-month period of the 2005 historical test year. Dr. Fairchild reflects this normalized amount in Exhibit A-9, C-1.

Landlord Transfer Fee

Q. What does SEMCO Gas propose regarding landlord transfer fees?

A. Typically, when SEMCO Gas transfers a gas service from one customer to another, without the requirement to make a physical visit to the property,

the Company charges the new customer a Commission approved transfer fee of $5.00. SEMCO Gas currently offers an exemption to this fee to landlords who sign a landlord agreement with the Company. The landlord agreement allows the Company to transfer responsibility for natural gas service to the protected properties back to the landlord, instead of shutting off service to these properties when the tenants are delinquent in their payments or when the tenant leaves the rental unit. The Company proposes that landlords with landlord agreements no longer be exempt from the transfer fee. The Company made 5,467 transfers into landlord accounts covered by landlord agreements during 2005. The Company expects roughly that same number of transfers into landlord accounts in the future. If this proposal is approved, the annual increase in revenue is expected to be $27,335. These numbers can be seen in Exhibit A-9, F-3-2. Dr. Fairchild reflects this revenue in Exhibit A-9, C-1

Tariff Sheet Changes

Q. Please describe Exhibit A-11, Schedule F-7.

A. Exhibit A-11, Schedule F-7 is a Summary of the Tariff Changes as proposed by the Company in this proceeding. In addition to the changes I am sponsoring, Mr. Alger, Mr. Lubbers, and Mr. Ketchum are also sponsoring various changes to the Company's tariff.

Q. Please describe page 1 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet A-21 of the SEMCO Gas Tariff and is updated to show the addition of the former Peninsular Gas Company ("Pen Gas") service territory to the service areas served by the Company. In Case No. U-14726, SEMCO Gas filed an application to merge the rates of its MPSC Division and its Upper Peninsula West (2) operational district (formerly Peninsular Gas Company). The parties entered into a settlement agreement recommending approval of the application. On May 26, 2006, the Commission approved the settlement.

Q. Please describe page 2 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet B-44 of the SEMCO Gas Tariff. Language has been included under B6.10 (A) to indicate that the Nonsufficient Funds Check (NSF) charge would be levied each time a check that has been presented to the Company for the payment of a gas bill has been returned to the Company marked NSF or Closed Account by the financial institution upon which the check is drawn. Current language allows only one charge per check, even though the check may have been returned NSF more than once.

Q. Please describe page 3 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet B-45 of the SEMCO Gas Tariff. The tariff language now clarifies that landlords are not exempt from the five dollar transfer fee, as I discussed earlier.

Q. Please describe page 4 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet B-55 of the SEMCO Gas Tariff. In support of the testimonies of Ms. Gardiner, Mr. Alger, and Mr. Ketchum, B10.2 (A) has been changed to include Lost and Unaccounted For, Company Use, and Gas in Kind as part of the Booked Cost of Gas Sold. These items have been removed from B10.2 (B) of the same sheet.

Q. Please describe page 5 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet E-2 of the SEMCO Gas Tariff as the Company proposes it might look. The categories LAUF, Uncollectibles, Conservation, and APR have been listed as surcharges.

Q. Please describe page 6 of Exhibit A-1, Schedule F-8.

A. This page presents Sheet E-4 of the SEMCO Gas Tariff. One instance of the term “customer charge” has been changed to “service charge,” and this charge has been increased to correspond to the rate design as proposed by the Company. The Distribution Rate has been removed.

Q. Please describe page 7 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet E-5 of the SEMCO Gas Tariff. The Customer Charge has been changed to correspond to the rate design proposed by the Company. The Distribution Rate has also been changed on this sheet to correspond to the proposed rate design.

Q. Please describe page 8 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet E-6 of the SEMCO Gas Tariff. Under the heading "Unmetered Service" the words ", except that no Customer Charge shall be applied" have been eliminated.

Q. Please describe page 9 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet F-20 of the SEMCO Gas Tariff. The Customer Charge and Transportation Rates have been changed to reflect the Company's proposed rate design.

Q. Please describe page 10 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet F-21 of the SEMCO Gas Tariff. The percentage of Gas In Kind has been changed. Mr. Alger supports the Gas In Kind amount in his testimony.

Q. Please describe page 11 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet F-27 of the SEMCO Gas Tariff which contains the Interruptible Transportation Service Rate Schedule.

Q. Please describe page 12 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet F-28 of the SEMCO Gas Tariff which continues the Interruptible Transportation Service Rate Schedule.

Q. Please describe page 13 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet F-34 of the SEMCO Gas Tariff. The percentage of Gas In Kind has been changed as supported by Mr. Alger.

Q. Please describe page 14 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet G-12 of the SEMCO Gas Tariff. Under the heading “Monthly Rate, Non-Gas Charges,”, the terms Customer Charge and Distribution Charge have been removed. In the last paragraph, the word “gas” has been corrected to the word “gate.”

Q. Please describe page 15 of Exhibit A-11, Schedule F-8.

A. This page presents Sheet G-13 of the SEMCO Gas Tariff. Under the heading “Minimum Charge,” the words “or service charge” have been added after the words “customer charge.”

Q. Does this conclude your direct testimony at this time?

A. Yes it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	

DIRECT TESTIMONY AND EXHIBIT OF

Malcolm R. Ketchum

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Malcolm R. Ketchum. I am a Vice President and Principal at Concentric Energy Advisors, Inc. ("CEA"), a management consulting firm with offices at 313 Boston Post Road, Marlborough, Massachusetts.

Q. PLEASE BRIEFLY DESCRIBE YOUR RELEVANT EXPERIENCE.

A. I have been involved in the energy industry for 32 years as a regulator, officer of a natural gas distribution and transmission company, and a management consultant. I have appeared on more than 100 occasions as an expert witness in regulatory proceedings. A copy of my resume is appended as Attachment 1 to this testimony. A listing of my previous testimony is appended as Attachment 2.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"). SEMCO Gas is a division of SEMCO Energy, Inc.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony describes SEMCO Gas's current rate structure for customers under the jurisdiction of the Michigan Public Service Commission (the "MPSC" or the "Commission") in what the Company sometimes calls the "MPSC Division," including what I perceive to be structural flaws in that current rate structure and

how these flaws impact the Company, its customers, and the Michigan economy. In addition, my testimony provides support for the alternative rate structure proposed by the Company that would address the structural flaws in the current rate design. Let me make it clear that, when I refer to "structural flaws," I do not mean that the Commission made mistakes in designing rates to recover the Company's revenue requirement. Rather, the Company's current residential rate design has certain attributes and perhaps unintended consequences, simply because of the way in which that rate design recovers costs from customers. In this case, a main effect of the current residential rate design is that the Company is hurt financially when customers conserve natural gas. A primary benefit of the alternative rate structure proposed in this case is to align Company and customer interests with respect to conservation. That alignment would support a "pro-conservation" state public policy, and, in fact, the Company is proposing a new customer conservation program in this case. I also present the Company's cost of service study and comparison of current and proposed rates.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring: (1) Exhibit A-6, Schedule F-6, entitled "Cost of Service Study", which is the Historical Year Cost of Service Study; (2) Exhibit A-11, Schedule F-1 entitled "Summary of Proposed Rates", which is a proof of revenue; (3) Exhibit A-11, Schedule F-4 entitled "Calculation of Pro Forma and Proposed Revenue", which is the detailed calculation of the proposed rates by class,; (4) Exhibit A-11, Schedule F-5 which is entitled "Comparison of Current and

Proposed Rates"; (5) Exhibit A-11, Schedule F-6, which is the Cost of Service Study with Known and Measurable Changes; entitled "Cost of Service Study"; (6) Exhibit A-12, Schedule 6, entitled "Declining Use Per Customer Initiatives", which summarizes the initiatives that have been implemented by other utilities to address the issues resulting from declining use per customer; (7) Exhibit A-12, Schedule 7, entitled "LAUF and Gas Cost Recovery Mechanisms", which summarizes the results of a local distribution company ("LDC") tariff survey of Gas Cost Recovery ("GCR") terms, Lost and Unaccounted-for ("LAUF") and Uncollectible expense recovery, and other tariff features designed to address issues associated with the recovery of these cost of service items; (8) Exhibit A-12, Schedule 8, entitled "Mains Replacement Programs", which summarizes several accelerated pipeline replacement programs approved for use elsewhere in the U. S.; and (9) Exhibit A-12, Schedule 9, entitled "Listing of Jurisdictions and Utilities Using Less Than 30 Years of Weather Normalization Data", which summarizes certain information about the use of shorter historical time series data for weather normalization. I will explain these exhibits later in my testimony.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized according to the following topics:

- Need for Rate Design Changes
- Rate Structure Alignment
- Economically Sound Rate Design
- Proposed Changes in Rate Design
- Decoupling and the Monthly Service Charge
- Energy Conservation Program Perspective
- Other Decoupling Approaches
- LAUF Gas Costs
- Uncollectible Expense
- Accelerated Pipeline Replacement Program
- Cost of Service Study
- Weather Normalization
- Rate Elements

THE NEED FOR RATE DESIGN CHANGE

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE ISSUES THAT HAVE CAUSED THE COMPANY TO PROPOSE TO CHANGE THE CURRENT RATE DESIGN FOR COLLECTING ITS REVENUE REQUIREMENT FROM RESIDENTIAL CUSTOMERS.

A. Ms. Gardiner and Mr. Dubay discuss the need for a change in rate design, from the Company's perspective, in their testimony. From my perspective, there are three main reasons that the proposed residential rate design change is appropriate.

(1) From a public policy point of view, as noted above, the current rate structure does not align Company and customer interests with respect to fostering the promotion of energy conservation and efficiency measures that would benefit both customers and the economy in Michigan; (2) the current structure does not recover the costs incurred by the Company in providing service to customers according to what I submit are sound economic principles; and (3) the combination of changes in the Michigan business environment and the key problematic attribute of the current rate structure (i.e., the collection of fixed costs using a volumetric charge) has resulted in the Company's not having a fair opportunity to recoup its costs of providing service, including earning the 11.0% return on equity ("ROE") that was authorized by this Commission in the Company's last general rate proceeding.[1]

RATE STRUCTURE ALIGNMENT

Q. PLEASE DESCRIBE FURTHER YOUR STATEMENT THAT THE CURRENT RATE STRUCTURE DOES NOT SUPPORT CONSERVATION AND EFFICIENCY EFFORTS.

A. The Company incurs substantial costs that relate to the operation of its transmission and distribution system for delivering natural gas to customers. These costs are considered "fixed" costs, because they must be incurred in order to maintain the system, regardless of the volume of natural gas that is delivered to customers. Said another way, these costs do not vary with the amount of natural

[1] Case No. U-14338;_Order at Page 2

gas customers consume. These costs include all ratebase, operations and maintenance, distribution plant, and administrative and general expenses that must be incurred in order to operate the distribution system, regardless of the volume of gas distributed. As an example, the cost of the meter outside of one's house is the same whether one uses any gas or not. The same can be said for the other fixed cost elements that I have listed. These fixed costs are classified as demand related or customer related in my cost of service study, Exhibit A-11, Schedule F-6, page 10. Under the Company's current rate structure, however, a significant amount of the Company's fixed costs are recovered through a volumetric charge, which is established based on normalized throughput at the time of a rate case. To the extent that the Company does not achieve the projected throughput levels determined in such a rate case, the Company will not recover all of the allowed fixed costs related to operating its system through this volumetric charge. Therefore, under the current rate structure, the Company's objective of recovering the costs of operating the distribution system, which can only be achieved when volumes are at least as high as those used for setting rates, conflicts with conservation efforts when those efforts reduce consumption below the level used to set rates.

Q. HAS THIS ISSUE BEEN RAISED IN THE INDUSTRY?

A. Yes. This issue has been the subject of considerable discussion in the natural gas industry in recent years, as evidenced by numerous articles in the trade press. In particular, in a joint position paper, the American Gas Association ("AGA") and

the Natural Resources Defense Council ("NRDC") identified rate design as one of the key issues that is hampering energy efficiency programs.[2] That joint position paper says:

> 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.[3]

Q. DID THE AGA AND NRDC OFFER A SOLUTION TO THIS ISSUE?

A. Yes. In the Joint Statement, the AGA and the NRDC urged public utility commissions to consider alternative ratemaking approaches that would encourage conservation programs and supported "mechanisms that use modest automatic

[2] "Joint Statement of the American Gas Association and the Natural Resources Defense Council" July 2004, pp. 1-2.

[3] "Joint Statement of the American Gas Association and the Natural Resources Defense Council" July 2004, pp. 1-2.

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."[4]

Q. HAS THERE BEEN OTHER REGULATORY SUPPORT FOR A CHANGE IN THE COMMONLY USED CURRENT RATE STRUCTURE WHICH COLLECTS A SIGNIFICANT PORTION OF FIXED COSTS IN A VOLUMETRIC CHARGE?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") endorsed the Joint Statement during its national convention in November 2005. The NARUC resolution reads, in part:

> Whereas, Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas.[5]

The AGA and NRDC Joint Statement and its endorsement by regulators are strong evidence of widespread recognition that the traditional rate structure of local distribution companies does not support conservation. This is, in my view, a particular problem in an era of higher and more volatile natural gas prices, when a

[4] Ibid. Page 2.
[5] http://naruc.org/associations/1773/files/GAS-2EnergyEfficiencyandInnovativeRateDesign.pdf

natural and appropriate response to what is happening in the marketplace is to encourage conservation. The issue has been addressed in several jurisdictions in a variety of ways, which I shall discuss in more detail later in this testimony.[6] The Northern States Power "fixed – variable" rate cited by NARUC and approved by the North Dakota Commission[7] is the form of rate that SEMCO Gas proposes in this case.

Q. HAS THE INTENSITY OF INTEREST AND ANALYSIS RELATED TO DECLINING USE PER CUSTOMER AND THE DISINCENTIVE TO PROMOTE ENERGY EFFICIENCY IN TYPICAL RATE STRUCTURES GAINED REGULATORY MOMENTUM IN RECENT MONTHS?

A. Yes. In a recent briefing paper, The National Regulatory Research Institute ("NRRI") presented what I view as a balanced review of what is often termed revenue "decoupling," because, in these kinds of rate designs, the link between customer usage and a utility's recovery of its revenue requirement is broken. That

[6] 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.

[7] State of North Dakota Public Service Commission, Northern States Power Company Natural Gas Increase Application, Case No. PU- 04 – 578, Order Adopting Settlement, June 1, 2005.

paper listed several jurisdictions where such mechanisms have been approved and several others where such mechanisms are under review. The type of full revenue decoupling reviewed in that paper was essentially of the type that has been in place for Baltimore Gas and Electric Company for several years. That particular mechanism adjusts revenues resulting from changes in volumes to authorized levels in subsequent periods by adjusting rates between rate cases.

Q. PLEASE SUMMARIZE THE NRRI'S CONCLUSIONS WITH RESPECT TO REVENUE DECOUPLING.

A. The NRRI briefing paper summarizes the recent regulatory activity on this issue. In that paper, the NRRI concludes that the regulatory approvals have been "motivated by at least one of two factors. The first was evidence showing an historical decline in gas usage per household, which was anticipated to continue in the future; the second pertains to the intent of state commission to have the utility aggressively and successfully promote energy efficiency."[8] Furthermore, the NRRI concludes that the positive features of revenue decoupling include "(1) increased opportunity for a utility to earn its authorized rate of return, (2) more revenue stability, (3) removal of disincentives for a utility to promote socially desirable energy-efficiency initiatives, and (4) elimination of major contentious aspects of a general rate case."[9] As I have discussed previously, the Company has

[8] Costello,Ken. "Revenue Decoupling for Natural Gas Utilities", The National Regulatory Research Institute, April 2006

[9] Ibid.

proposed a change in its current residential rate structure to address these same key issues.

Q. HAS NRRI IDENTIFIED SOME CONCERNS THAT HAVE BEEN RAISED WITH REGARD TO THESE TYPES OF REVENUE DECOUPLING PROGRAMS?

A. Yes. These include concerns surrounding public acceptability, the implementation of these mechanisms, and general concerns about reduced incentives for utilities to be innovative in new ratemaking and promotional activities.

Q. DOES THE FIXED MONTHLY CHANGE IN THE RATE DESIGN BEING PROPOSED BY THE COMPANY OVERCOME SOME OF THE NEGATIVE ASPECTS OF REVENUE DECOUPLING MECHANISMS THAT WERE REVIEWED BY THE NRRI?

A. Yes. For one, SEMCO Gas's proposed rate structure is not a "tracking" mechanism, as is the case with some revenue decoupling rate mechanisms. As I will discuss in greater detail later in my testimony, the Company is proposing what is known as a "straight fixed/variable" rate design, with a fixed charge to recover fixed distribution costs from residential customers. This fixed monthly service charge should be easier for customers to understand than the Company's current rate design and is expected to have or gain customer acceptance, as explained by Ms. Gardiner. In addition, the fixed monthly service charge proposed by the Company to recover current distribution costs from current

distribution customers will be easier to administer than many of the more complex mechanisms that have been proposed elsewhere. Finally, because the Company will simply be recovering fixed costs in a different way (essentially by substituting a per customer billing determinant for a per unit of consumption billing determinant), the proposed change in the rate design will not reduce the Company's incentive to develop innovative programs to improve efficiency, reduce costs, or to expand its customer base.

Q. HAVE CHANGES IN RATE DESIGN BEEN DISCUSSED IN MICHIGAN AS A BARRIER TO ENERGY EFFICIENCY PROGRAMS THAT MUST BE REMOVED?

A. Yes. The AGA and NRDC Joint Statement discussed above was referenced by Mr. Gary Kitts of the MPSC Staff in the recent Staff report on energy efficiency. In the Staff paper, Mr. Kitts identifies issues that impede energy efficiency programs and cites the AGA and NRDC paper as providing an excellent explanation of the rate design issues. Furthermore, Mr. Kitts recommended a high fixed cost component of rates as an approach to "more closely align the interests of utility shareholders and customers with respect to energy efficiency."[10]

[10] Michigan Public Service Commission Staff Report Energy Efficiency Programs, January 31, 2006, p. 5.

ECONOMICALLY SOUND RATE DESIGN

Q. PLEASE EXPLAIN WHY THE CURRENT RATE STRUCTURE IS NOT, IN YOUR VIEW, CORRECTLY RECOVERING THE COSTS THAT SEMCO GAS INCURS TO PROVIDE SERVICE TO CUSTOMERS.

A. The Company's current rate structure recovers many of the fixed costs associated with the delivery of natural gas to customers through a variable or volumetric charge. Ms. Gardiner's testimony contains a sample bill showing where the volumetric recovery of these fixed costs occurs, in the non-GCR volumetric charge. Economic principles support the proposition, however, that fixed costs, including the cost of capital, should be collected in fixed charges, and variable costs should be recovered in variable charges. For example, Dr. Alfred E Kahn in his widely quoted text ***The Economics of Regulation*** says the following: "The two-part tariff, generally credited to John Hopkinson, an English engineer, and almost universally used by electric and gas utilities for large volume sales at wholesale and to industrial users, represents an effort to apply just such a principle. The first part—the energy commodity or running charge-embodies the variable costs, properly charged to all customers, and is levied on a per unit of consumption basis (per kWh or per MCF of gas). The second part—the demand or capacity charge—is a charge for the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of *capacity*: the demand charge, therefore, distributes the costs of providing the capacity the fixed,

capital costs—on the basis of the respective causal responsibilities of various buyers for them."[11]

In order to charge for residential customer's contribution to peak demand, the Company would have to do one of two things: install a time-sensitive meter[12] that would measure and record each customer's use at the time of the peak demand on the system or develop an algorithm to estimate usage at the time of peak by, for example, developing a relationship between heating degree days and usage at the time of the peak. However, since residential customers have relatively homogenous load patterns, an appropriate fixed monthly service charge can be developed that equitably collects the fixed costs of providing service. Very often, in cost studies, the residential class is treated as a homogenous group for costing purposes. This is the case for SEMCO Gas historically; the fixed costs allocated to the residential class are typically averaged over all customers in the class.

Q. DOES RECOVERY OF THE COMPANY'S FIXED COSTS IN A FIXED MONTHLY SERVICE CHARGE, AS PROPOSED BY SEMCO GAS, INAPPROPRIATELY AFFECT THE PRICE SIGNAL CUSTOMERS RECEIVE AND THUS REDUCE THEIR INCENTIVE TO CONSERVE?

A. No. Under the Company's proposed rate design, the economic price signal associated with the variable commodity cost dominates the bill and tells

[11] Kahn, Alfred E., The Economics of Regulation; Principles and Institutions, Volume I, John Wiley & Sons, Inc. New York, 1970, Page 95.

[12] This is because residential customers, who in the case of SEMCO Gas comprise approximately 91% of all customers, do not have demand meters installed.

customers they need to conserve in the winter when bills are highest, because of typically higher use during the heating season and because of high prices usually associated with high demand for the commodity in the winter.

Q. IS THE COMPANY'S CURRENT RATE STRUCTURE A COMMON STRUCTURE IN THE UTILITY INDUSTRY?

A. Yes. It is true that rates for most electric and gas utilities are not properly structured, in terms of ensuring that fixed costs are recovered exclusively in fixed charges. Many utility rate structures recover a significant portion of the fixed cost of distribution service through a variable charge. This way of collecting costs is unlikely to concern a utility when per customer usage is flat or increasing, since, in such a circumstance, the variable charge is probably producing sufficient revenues to recoup the costs of providing service. There are, however, examples of utilities where the utility's fixed costs are collected in fixed charges. One such gas company example is Atlanta Gas Light ("AGL"). AGL has a completely unbundled rate consisting of a customer charge and a demand charge. This rate design is summarized in Exhibit A-12, Schedule 6. Briefly, in the case of AGL, the residential contribution to peak demand is based on an estimate of individual use at the time of the peak. Because the AGL market has been opened up to competition, marketers provide the gas commodity and charge for their product on a volumetric basis.

A second form of rate design wherein the utility recovers its fixed costs in a fixed charge is the fixed–variable rate design implemented by Northern States Power in North Dakota. It is this rate structure that is being proposed by SEMCO Gas in this case.

Q. TO WHAT EXTENT HAVE RATE DESIGN FEATURES THAT ADDRESS DECLINING USE PER CUSTOMER BEEN APPLIED IN JURISDICTIONS AROUND THE COUNTRY?

A. The quote from NARUC above identifies seven utilities that have implemented decoupling mechanisms or other rate designs to address the issue of declining use per customer. There are at least eight additional companies that have implemented decoupling rate designs (not counting increased customer charges and declining block rate designs), eight additional companies that have filed decoupling rate designs or mechanisms, and six state utility commissions that have requested additional information about such programs. These programs and initiatives are discussed in Exhibit A-12, Schedule 6. The point is that gas distribution companies and regulators across the country are facing and addressing this issue in growing numbers.

Q. THERE ARE SEVERAL MECHANISMS TO ADDRESS THE DECLINING USE PER CUSTOMER PROBLEM. WHY IN YOUR OPINION IS THE APPROACH SELECTED BY SEMCO GAS THE PROPER CHOICE FOR THIS COMPANY?

A. The rate structure proposed here by SEMCO Gas would provide the company with the ability to actively promote conservation programs without creating financial disincentives for the company. This rate structure is a practical solution that avoids the need for expensive metering and is readily understood by customers; namely, a fixed monthly service charge for collection of all fixed costs for the residential class. As I have said, such a charge has been approved for Northern States Power's North Dakota gas utility and has found popular acceptance.[13] Ms. Gardiner discusses the Company's specific reasons for making this proposal in her testimony. In summary, Ms. Gardiner identifies the following seven reasons why the proposed rate design makes sense for SEMCO Gas: (1) the proposed design is easy to understand; (2) a fixed service charge rate design is familiar to customers; (3) it is a lower cost method to implement than other decoupling approaches; (4) it has a stabilizing impact on monthly bills; (5) it would not be weather sensitive; (6) it would not mask proper price signals; and (7) it would extend the time between rate filings driven by declining use per customer, thus lowering regulatory costs. I agree with Ms. Gardiner's analysis of the benefits of this structure for SEMCO Gas, compared to the current rate design and other approaches to "decoupling" revenue collection from sales.

[13] I have had direct telephone contact with Mr. Mike Diller, the Director of Accounting on the North Dakota staff. Mr. Diller indicated that there has been very good customer acceptance of the new rate. The new rate plan was initially rolled out in the summer months and, when compared against a previous summer month bill, it appeared to be a significant increase as a percent of the distribution charge. There were a few complaints at that time, however, and, when customers were informed that the distribution rate would be held constant in the winter months, these customers were satisfied. Mr. Diller said to me that "It's a common sense approach that's good from a customer and company perspective."

In this regard; I would like to emphasize point two above; namely, that there are many other utilities and services (such as; telephone service, internet service, cable TV service, airline service, garbage service, car leases, etc.) where fixed fees for fixed cost recovery are common. Consumers are used to and understand fixed charges for the basic fixed costs associated with these services.

THE PROPOSED CHANGES IN RATE DESIGN

Q. BEFORE DISCUSSING EACH OF THE ELEMENTS OF THE OVERALL PROPOSAL, PLEASE LIST THE RATE DESIGN PROPOSALS THAT SEMCO GAS REQUESTS THAT THE COMMISSION APPROVE IN THIS PROCEEDING.

A. Ms. Gardiner describes the Company's proposals in detail in her testimony. In essence, those proposals contain three changes from the current rate structure: (1) substitution of a single fixed monthly service charge for the recovery of fixed distribution system costs that are currently being recovered, in part, in a variable charge; (2) collecting LAUF gas costs as a cost of gas item in the GCR process, or, alternatively, collection of LAUF gas costs in base rates, subject to an annual "true-up" for actual LAUF costs and volumes; and (3) an annual net true-up that accounts for a) the true-up of Uncollectible expense, to ensure that the Company recovers its actual cost for this expense or, conversely, that customers do not overpay for this expense on an annual basis, b) the actual capital-related costs associated with the proposed program to accelerate the replacement of bare steel pipe and five large compressors, c) the collection of the energy conservation

program costs. I will provide my perspective on the energy conservation program and on the replacement program below. The energy conservation program is described in Mr. Lubber's testimony, and the pipeline replacement program is described in further detail in Mr. Larsen's testimony.

DECOUPLING AND THE MONTHLY SERVICE CHARGE

Q. PLEASE FURTHER EXPLAIN THE TERM "REVENUE DECOUPLING."

A. The term "decoupling" in this context means the separation of the collection of fixed costs, including the cost of capital, from the variable determinant (in this case, the volume of natural gas consumed by the customer and used to calculate both the distribution charge and GCR charge on a residential customer bill).

Let me explain this concept from a more technical perspective. A typical class cost of service analysis can generally be described as following three steps; namely, functionalization, classification, and allocation. When one is trying to understand the concept of revenue decoupling, the focus is on the classification step. In this step, the analyst determines which costs are commodity- or energy-related, which costs are demand-related, and which costs are customer-related. Commodity related costs vary from minute to minute, hour by hour, and month by month, because they reflect the energy consumed by customers. It is appropriate for these costs to be collected in a variable charge (i.e., in a per ccf charge, per therm charge, or per kWh charge, as the case may be). Demand-related costs are caused by the demand put on the system at peak times. These costs do not vary

from minute to minute or hour to hour. In that sense, demand-related costs are fixed. Finally, customer-related costs are driven, broadly, by the number of customers on the system. These costs also are properly considered fixed.

As noted earlier in my testimony, fixed costs are collected in variable or volumetric charges by many gas utilities throughout the country, and this is the case currently for SEMCO Gas. Under this type of rate structure, sometimes the utility may collect more than it needs to cover these fixed costs (when throughput volumes are high) in other periods with low throughput the utility may collect less than it needs to cover its fixed costs. In the case where the trend in usage is sharply declining and customer growth is relatively low, as appears to be the case for SEMCO Gas, the Company will not recover all of its fixed costs of providing service through the volumetric portion of its rates.

From a more practical perspective, while it is in the Company's financial interest to do so, it is unclear to me how the Company would be able to promote increased usage when gas prices are substantially higher than in the past. It also is questionable, from a public policy perspective, whether the Company's promoting increased usage of natural gas is a sound idea, even if SEMCO Gas were somehow able to induce such behavior by customers. Also, adding new customers to the Company's system appears to be a struggle in the current Michigan economic environment and does not necessarily solve the problem.

If the Company's fixed costs were collected in a fixed monthly service charge, the amount of natural gas customers' use would not affect the Company's recovery of its revenue requirement, positively or negatively. In fact, the Company would be financially indifferent to conservation under the proposed fixed monthly service charge rate design. By contrast, under the Company's current rate structure, the Company is not indifferent to conservation, because conservation, irrespective of why it is occurring, reduces the amount the Company collects in the volumetric or variable distribution portion of a residential customer's bill. In a scenario where customers' consumption is reduced below the level that was projected when rates were established, the Company's margin is reduced by conservation and, all else equal, it will not recover its costs of providing service.

Q. WHAT ARE SOME OF THE OTHER BENEFITS OF BREAKING THE LINK BETWEEN USAGE AND FIXED COST COLLECTION?

A. One of the other benefits of collecting fixed costs in fixed charges is that this rate design tends to offset higher winter heating season bills by spreading the recovery of the fixed costs of the distribution system out evenly over a twelve-month period. Under a typical rate structure, where the distribution charges are recovered volumetrically, the distribution charge component of a customer's bill recovers the majority of the fixed costs of the distribution system in the winter heating season, when the customer's usage and the total bill are the highest. This results in customers paying for higher per unit gas costs, increased usage of gas, and a greater proportion of the distribution system costs in the winter period.

As Ms. Gardiner notes in her testimony, it makes more sense to "levelize" fixed cost recovery. If the Company's underlying costs to stand ready to serve its customers are the same each month of the year, why should the Company charge more to recover those fixed costs in the winter heating season when bills are the highest?

The answer to this rhetorical question is that *there is no good reason to design rates this way*. The only rationale is that it has always been done that way. While some point to cost differences to support maintaining the current rate design, increasingly, the cost for any residential customer is converging to or at the mean, since the infrastructure for these customers is essentially the same.[14] As noted earlier, upstream demand costs could be differentiated if demand meters were available, or the AGL solution could be adopted, where demand estimates are made for individual customers. On the other hand, cost considerations, simplicity, common sense, and understandability support taking the approach proposed by SEMCO Gas, rather than the more complex approaches that many other utilities have taken in addressing the decoupling issue.

[14] Residential customers have generally the same size meters and similarly sized service mains, according to information provided by Company engineers.

Q. DOES THE COMPANY'S PROPOSED RATE DESIGN RESOLVE THE DISINCENTIVE TO CONSERVATION THAT IS INHERENT IN THE COMPANY'S CURRENT RATE DESIGN?

A. Yes. Modifying the Company's current rate design to conform more closely to what I consider sound economic principles by collecting fixed costs through fixed charges and variable costs through the variable component of rates will decouple the Company's revenue requirement from throughput and therefore eliminate the disincentive that exists today in the residential rate structure with respect to conservation. The Company's proposed rate design is a straightforward rate design that would apply to all residential customers (which represent 91% of all customers) and would consist of a fixed monthly service charge to collect fixed costs and a variable charge to collect gas costs through the GCR. As noted in Ms. Gardiner's testimony, the Company also proposes a third billing element in which various proposed "true-ups" would be aggregated into a net surcharge or credit.

Q. ARE THERE CHANGES IN THE INDUSTRY THAT SUPPORT MODIFYING THE COMPANY'S EXISTING RATE STRUCTURE IN THE MANNER THAT YOU SUGGEST?

A. Yes. First, there has been a significant philosophical shift toward reliance on the market to provide discipline for prices. Many electric and gas utilities are now fully or partially unbundled, including those in Michigan. This means that upstream costs, such as power production, transmission of power, wellhead production cost for natural gas, and pipeline delivery costs have been separated or

unbundled from the rates charged for distribution services. The supply of commodities, natural gas at the wellhead and electricity, is now often priced based on market determinations.

A second factor is that there has been a change in the relative price of the commodity as compared to the fixed capital charges associated with delivering the commodity to customers. In a nutshell, the fixed cost portion of a residential bill is not what is driving the overall bill. Instead, the commodity charge is the largest component of the bill in the current higher gas price environment. This being the case, the Company's proposed rate design would impact a small portion of the bill in a way that makes the bill more understandable and removes the distribution cost component from the part of the bill that varies with the usage.

There is another consideration, which Ms. Gardiner discusses in her testimony. Recent surveys show that customers continue to be confused about LDC profits when gas costs are relatively high. In the absence of cost disallowances, gas costs are passed through to customers on a dollar-for-dollar basis. LDCs do not make a profit on the cost of gas itself. Confusion arises, as noted, when a portion of an LDC's revenue requirement is collected in a volumetric distribution charge. To customers, this sometimes looks as if an LDC is profiting on the commodity itself. Perhaps only people involved in the regulatory process understand that, while the same volumes are used as a billing determinant for the distribution and

GCR-type charge, the LDC is not "profiting" on the commodity portion of the bill.

Q. HOW ARE CUSTOMERS IMPACTED BY THE CURRENT GAS SUPPLY MARKET?

A. Customers are experiencing significantly higher monthly bills, particularly in the winter months, caused largely by higher commodity costs in the market. In addition, customers are experiencing more volatility in monthly bills, as the commodity market swings in response to weather, storage inventory data, and other events (such as natural disasters) affecting production itself or market perceptions. I believe that customers would welcome an approach to billing that would stabilize the service portion of their bills and offset higher commodity cost in winter, by lowering the customer bill in the winter compared to what happens to their bills under the current rate design.

It also seems to me that, in this era of higher and more volatile gas costs, customers would welcome the energy efficiency and conservation efforts that aligning Company and customer interests should produce.

Q. WHAT IS THE SITUATION WITH RESPECT TO HIGH ENERGY BILLS FROM THE REGULATOR'S VANTAGE POINT, IN YOUR VIEW?

A. Regulatory bodies throughout the country have been confronted by complaints regarding high bills and public confusion about who is reaping the profits from

higher market prices for natural gas.[15] As Mr. Kitts points out in his paper, the Commission issued an order in Case No. U-14667 that directed Staff to "recommend alternatives designed to improve energy efficiency, make energy utility services more affordable to Michigan ratepayers, and enhance the State's economy."[16] There have been a number of other initiatives among regulators in the Midwest in recent months in an effort to address the situation. For example a conference sponsored by the Minnesota Public Utilities Commission, the Minnesota Department of Commerce, the U.S. Environmental Protection Agency and NARUC was held on December 6, 2005[17] to address the same issues described in the paper by Mr. Kitts.

Regulators from many regions of the country were hopeful that unbundling of service and establishing a competitive supply market would provide the discipline of the market to keep commodity prices low. The achievement of these goals using the unbundled market approach has proven to be elusive for reasons discussed in more detail below. I believe, however, that a well-functioning competitive market place can also be well served by the rate design that the Company is proposing.

Q. WHAT IS THE PERSPECTIVE IN OTHER PARTS OF THE COUNTRY?

[15] www.wisconsinpublicservice.com/home/naturalgas2005.asp
[16] Op. cit., page 1.
[17] http://www.raponline.org/conferences/workshopinfo2.asp?id=1

A. Many jurisdictions have addressed, or are in the process of addressing, the issue of declining use per customer, as evidenced by the quote from the NARUC resolution above, and by the NRRI position paper that I discussed above. Exhibit A-12, Schedule 6 summarizes the types of programs that have been implemented to address this issue. In particular, revenue decoupling programs have been implemented in several jurisdictions and have recently been proposed by several LDCs as the solution to revenue instability stemming from declining use per customer and to align the interests of the customers and the LDC, with the goal of encouraging conservation for the benefit of customers. In addition to the AGL and Northern States Power fixed–variable rate designs discussed previously and the several other examples listed by NARUC, the Commissions in Indiana, New Jersey, Utah, Washington and Ohio are currently reviewing decoupling programs that have been proposed as solutions to the issues of energy conservation and weather normalization.

ENERGY CONSERVATION PROGRAM PERSPECTIVE

Q. THERE WERE SIGNIFICANT ENERGY CONSERVATION PROGRAMS AND CONSIDERABLE INVESTMENTS MADE IN CONSERVATION IN THE LATE 1970'S, THE 1980'S, AND INTO THE EARLY 1990'S. WHAT HAPPENED TO CHANGE THAT?

A. Higher prices for natural gas were the norm in the wake of the Arab Oil Embargo in 1973. Around that time, utility-sponsored energy efficiency programs were mandated. As Mr. Kitts pointed out in his paper, the price of the commodity

declined in real terms in the mid 1990's, and many energy conservation programs simply were no longer cost-effective in the short term.[18] The Power Plant and Fuel Use Act which had restricted the use of natural gas in the late 1970's and early 1980's and which, together with supply initiatives had led to the gas bubble in the 1980's and 1990s, was repealed in 1987. Lower natural gas prices, lower capital costs, and efficient new generating technology led to a boom in the construction of natural gas-fired power plants.

Q. WHAT HAS HAPPENED TO TURN NATURAL GAS PRICES AROUND AND ONCE AGAIN TO MAKE CONSERVATION A PRIORITY AND TO GIVE RISE TO THE ISSUE ADDRESSED IN MR. KITTS' PAPER AND IN THE JOINT RESOLUTION OF THE AGA AND NRDC QUOTED PREVIOUSLY?

A. This situation is summed up nicely in a paper that was published a little over a year ago by the American Council for an Energy–Efficient Economy.[19] Essentially, the paper states that there was a dozen years of low natural gas prices from the late 1980's to the early 2000's that led to two trends that created the market situation today. First, this period of low prices made the energy efficiency programs of the 1970's and 1980's significantly less cost-effective. There also was concern about whether utilities should have a role in such programs, or

[18] Michigan Public Service Commission, Staff Report, Energy Efficiency Programs, Mr. Gary Kitts, principal author, January 31, 2006, Page 16.

[19] Martin Kushler, Ph.D., Dan York, Ph. D, and Patti Witte, M.A. , Examining the Potential for Energy Efficiency To Help address the Natural Gas Crisis in the Midwest, American Council for an Energy-Efficient Economy, Washington, D.C. January 2005 , Page 1.

whether others (including government or those marketing energy conservation programs or products) were better positioned to promote energy efficiency.

The second trend in energy conservation was a massive shift toward natural gas as the fuel of choice for electric power generation, due in large part to environmental regulations that affected the permitting of plants and uncertainty about the electricity marketplace, which favored the construction of natural gas-fired units with lower capital costs. Over 90 percent of the 200,000 MW of new electric generation added in the U.S. over the five years from 2000 through 2004 was natural gas-fired.

These two trends have led to a demand supply imbalance that has pushed natural gas prices up dramatically and increased price volatility. It should also be noted that there has been a noticeable decline in deliverability from gas wells in traditional North American supply basins over the past several years.[20]

Q. WILL CONSERVATION BE PROMOTED IF THE LINK BETWEEN USAGE AND FIXED COST RECOVERY IS BROKEN?

A. Yes, adoption of the Company's proposed rate design removes a financial disincentive to promoting conservation and, in that sense, breaking the link between usage and fixed cost recovery should promote conservation. In fact, the Company has offered to implement a new energy efficiency and conservation

[20] Ibid. Page 3.

program as part of this filing. This program is described fully in the testimony of Company witnesses Gardiner and Lubbers.

Q. ARE THERE ANY LESSONS LEARNED FROM PAST EXPERIENCE WITH UTILITY-SPONSORED CONSERVATION PROGRAMS THAT SHOULD BE KEPT IN MIND NOW?

A. Yes. In general, the rate treatment that was implemented to support conservation programs during the 1970's, 1980's and early 1990's was a very time intensive, expensive, and controversial process. Conservation programs were implemented at many utilities while they maintained essentially the same rate structure as is currently in place at SEMCO Gas; a volumetric distribution cost recovery mechanism. At that time, the regulatory agencies recognized, as I have discussed in the present situation, that declining usage has a negative impact on a Company's ability to earn its allowed rate of return. In order to create a structure where the utilities were indifferent to the implementation of these programs, the agencies often allowed the utilities to file for the recovery of both the actual cost of the conservation programs and recovery of lost net revenues associated with conservation the programs produced.

Q. PLEASE EXPLAIN THE ISSUES ASSOCIATED WITH THE RECOVERY OF PROGRAM COSTS.

A. Conservation program costs were typically established prior to the year in which they were incurred. Some programs, such as that approved for Detroit Edison in

Michigan, required that the costs of the program be recovered in the year in which they were expected to be incurred. As I understand it, under the Detroit Edison recovery mechanism, this was accomplished through a five-step process that included forecasting the demand-side management ("DSM") costs for the year, approval of costs by the Commission, tracking costs, and reconciliation and recovery mechanisms to true-up the actual and forecasted costs.

In addition to the actual costs of DSM efforts, many companies, including Detroit Edison, were granted the recovery of lost revenues. In the case of Detroit Edison, lost revenues could be recovered if the utility met three hurdles: (1) the utility's actual sales for the year were lower than those upon which rates were set; (2) its achieved return on equity for that year was lower than its authorized rate of return on common equity for that year; and (3) the utility's lost revenue can be demonstrated after the fact.[21] While the calculations to demonstrate compliance with the first two criteria are fairly straight forward, the analysis required to demonstrate that the utility had met the third criterion was extensive. In order to demonstrate the utility's lost revenue, it was necessary to conduct extensive load research studies, some of which included metering techniques to determine the level of customer demand, sometimes even to the appliance level.

The detailed data that was complied from the load studies was then used to construct demand elasticity models that were used to disaggregate the decline in

[21] Michigan Public Service Commission Order No. U-10102, January 21, 1994, p. 161.

usage into its various components (i.e. weather, normal growth, conservation etc.). Once the studies were filed, the models were often the subject of much controversy, and the regulatory review process was extensive and costly for all participants. Utilities applied for the recovery of lost revenues on an annual basis.

Finally, as further encouragement to support the DSM program, in the Detroit Edison case, the Commission approved a "sliding scale" of bonuses and penalties for shareholders.[22]

Q. WILL THE RATE DESIGN PROPOSED BY THE COMPANY ELIMINATE THE ISSUE OF TRYING TO TRACK CONSERVATION PROGRAM IMPACTS?

A. Yes, it will. The Company's proposed program is a very straight forward proposal that will provide the Company the opportunity to recover its allowed revenue requirement, without the complex tracking programs that have been implemented in other jurisdictions. Simplicity is one more reason to adopt the Company proposed rate design.

Q. WILL THE COMPANY DO THE ACTUAL INSTALLATION OF CONSERVATION RELATED EQUIPMENT AND DEVICES?

A. No. The Company proposes to use contractors, with an emphasis on engaging Michigan-based contractors for this work. This will have the added benefit,

[22] Michigan Public Service Commission Order No. U-10102, January 21, 1994, p. 165.

beyond the conservation impact on customer's bills, of providing some additional stimulus for the Michigan economy. Again, Ms Gardiner and Mr. Lubbers describe the proposed program in more detail.

OTHER DECOUPLING APPROACHES

Q. WHAT OTHER METHODS HAVE BEEN IMPLEMENTED TO ADDRESS THE LINK BETWEEN USAGE AND FIXED COST RECOVERY?

A. LDC's and other utilities have implemented a variety of programs designed to improve the recovery of fixed costs. These programs, which are summarized in Exhibit A-12, Schedule 6, include price elasticity and conservation adjustments, declining block rates, partial or full revenue decoupling, weather normalization, "trended" normal weather, multi-year forecasts, and higher customer charges. While the other programs described in this exhibit may achieve the specific goals established for each of the companies, in my opinion, under the circumstances here and for the reasons stated previously, the Company's proposed approach is superior to those proposed or implemented by others.

Q. WHY HAS SEMCO GAS NOT PROPOSED TO IMPLEMENT ANY OF THESE OTHER ALTERNATIVE RATE MECHANISMS?

A. The programs listed in the previous answer described in my Exhibit A-12, Schedule 6 have been implemented to address declining use per customer issues facing other utilities. Generally, these issues have included concerns about the

collection of fixed costs, but may have been tailored to the specific circumstances of the individual utilities.

The Company examined these ratemaking mechanisms as part of preparing this filing. The Company concluded, and I agree, that proposing to redesign the Company's rates such that they provide for cost recovery that more closely matches cost causation (meaning that fixed costs are recovered in fixed charges and variable costs are collected in variable charges) and doing so using a fixed monthly service charge for the non gas portion of costs, is a simple, understandable way to align Company and customer interests with respect to conservation, while addressing the issue of declining use per customer in a way that is beneficial to all stakeholders. Most of the other methods, particularly the revenue decoupling mechanisms discussed in the NRRI Paper and addressed earlier in my testimony, involve complicated measurement, accounting, and deferred revenue collection that is unnecessarily complex, particularly for a utility the size of SEMCO Gas, and are not as understandable as the Company's proposal.

Q. PLEASE DISCUSS THE PROPOSED FIXED MONTHLY SERVICE CHARGE.

A. With regard to the collection of its fixed costs of serving residential customers, the Company proposes a fixed monthly service charge for all the costs incurred to provide distribution service for its residential customer class. The Company is

not proposing to change the rate structure, at this time, for the other classes of service, because, as Ms. Gardiner explains in detail in her testimony, (1) the vast majority of Company customers are in the residential class, (2) the residential class is much more homogenous than the other classes, and (3) the other large classes have transportation rates, which may include demand charges, and in those classes are much more likely to purchase their own gas**.**

Q. PLEASE EXPAND ON THE BASIS FOR YOUR RECOMMENDATION THAT THE COMPANY BE PERMITTED TO IMPLEMENT A FIXED MONTHLY SERVICE CHARGE FOR THE RECOVERY OF THE FIXED COSTS INCURRED TO PROVIDE SERVICE TO THE RESIDENTIAL CLASS.

A. The current rate structure, which recovers much of the fixed costs of the distribution system through volumetric or variable charges, does not, in my opinion, give the Company a fair opportunity to recover its costs of providing service and achieve its allowed rate of return between rate cases, when use per customer is declining, as is the case in the Company's Michigan service territory. This is because those volumetric rates are based on levels of consumption that are higher than the throughput levels that are actually achieved during the rate effective years in a declining use environment.

Moving to a fixed monthly service charge, which recovers the Company's fixed service and facilities costs independent of usage, would eliminate the effect of

declining use per customer on the Company's recovery of fixed costs, including its Commission-authorized rate of return.

Q. PLEASE REVIEW THE BENEFITS OF THE FIXED MONTHLY SERVICE CHARGE.

A. Moving to a fixed monthly service charge has numerous benefits. First, from a customer perspective, the concept of a fixed monthly service charge is straightforward and easy to understand. Under the approach proposed by the Company, a residential customer will know that the monthly fixed cost for having natural gas service available to him or her is $24.09. This service charge rate is based on data found in my Cost of Service study, Exhibit A-11, Schedule F-6 and does not include LAUF. If LAUF is not collected in the GCR as proposed, this fixed monthly Service Charge would be $25.18. The total customer bill will vary based on usage, because the commodity cost will continue to be collected in a variable charge and reflect the customer's individual consumption pattern. Changing to a bill consisting of primarily a fixed charge and a volumetric GCR charge will provide customers with the appropriate economic signals to understand how their usage impacts their total monthly bill. This knowledge will enable the customers to make informed choices regarding their consumption and will promote conservation efforts, because customers will continue to see the financial effects of their efforts to conserve energy in the form of reduced volumetric GCR charges.

In addition, if the Company's fixed costs are recovered through a fixed monthly service charge, as opposed to through a combination of a customer charge and a variable distribution charge that varies with usage, the bills to customers will be more stable. This is because the Company's fixed costs would be collected on a levelized basis throughout the year, just as the Company stands ready to provide service throughout the year. While the effect of levelizing a portion of the bill may be relatively modest, at least it will be clear to customers what is causing their bills to change each month (namely, how much natural gas they use). This should result in fewer high bill complaints and make it easier to explain to customers who do complain why their bills appear higher than normal.

From the Company's perspective, what is known as a straight fixed-variable rate design structure offers benefits. First, such a structure appropriately matches revenues with costs and provides the Company a fair opportunity to recover its fixed costs in a declining use environment. In general, all else equal, providing a fair opportunity to recover fixed costs should decrease the need for rate relief and reduce frequency of rate cases, and the time and expense associated with them. Secondly, the implementation of this type of rate design is more straight-forward than other cost recovery mechanisms, which are typically substantially more complex and thus require significant regulatory oversight.

The Commission benefits from adoption of the proposed residential rate design, in the form of fewer customer complaints and the potential for decreased frequency

of rate cases. In addition, the fixed charge for fixed cost recovery is easier to audit than a review of the current rate structure. Also, to the extent that the Commission wishes to support a "pro-conservation" public policy, adoption of the Company's proposed rate design is, as noted previously, a key element in aligning Company and customer interests in favor of such a policy.

Q. WHAT IS THE IMPACT OF MOVING TO A FIXED MONTHLY SERVICE CHARGE ON CUSTOMER BILLS?

A. As is illustrated in Mr. Alger's analysis, since fixed costs are a small portion of the total customer bill, especially in the winter months or in periods of high gas prices, adoption of the proposed rate design results in no apparent intra-class subsidization. The cost to provide service is essentially the same for all residential customers, regardless of the volume of gas consumed. In a normal winter, most customers will see a reduction in their overall bills compared to the current rate design, since the fixed monthly charge is a replacement for both the monthly customer charge and the volumetric distribution charge and because some of the distribution cost that would previously been collected in the winter will have been collected in the summer. Furthermore, as is discussed by Mr. Alger, the same percentage of lower income customers will benefit from moving to a monthly service charge as the general body of residential ratepayers, since the Company's low-income customers generally have the same percentage of high usage customers as the rest of the Company's residential customers.

LAUF

Q. PLEASE DISCUSS THE GAS COSTS YOU BELIEVE SHOULD BE INCLUDED IN THE VARIABLE CHARGE TO RESIDENTIAL CUSTOMERS.

A. From a rate design perspective variable gas costs for which customers are charged, should be recovered in the GCR portion of the bill. LAUF gas costs are a variable cost and part of the cost of gas, and therefore this cost should be collected in a charge that is paid for on an as incurred basis, in the same way as the rest of the variable gas cost, through the GCR mechanism.

Q. PLEASE DISCUSS COLLECTING LAUF GAS COSTS IN THE GCR PROCESS AS A COST OF GAS AND, ALTERNATELY, IF THE GCR CONCEPT IS NOT APPROVED, COLLECTING LAUF COSTS SUBJECT TO AN ANNUAL TRUE-UP.

A. The Company proposes to recover the cost associated with LAUF gas through the GCR process. The Company has proposed that the LAUF gas costs be collected in this way because, as Ms. Gardiner explains, LAUF gas costs are a cost that is directly associated with the commodity purchased and sold and therefore should recovered, audited and reconciled in a manner consistent with the Company's gas costs. Mr. Warsinski's testimony shows how the Company accounts for LAUF gas costs.

What I plan to address is how LAUF gas costs are recovered elsewhere in the country. The majority of gas distribution companies throughout the country consider LAUF gas costs to be a cost of gas, and those LAUF gas costs are generally collected through the gas cost adjustment mechanism.

I have undertaken a survey of what is being done elsewhere and have reviewed and summarized numerous tariffs of companies throughout the country. The results of this survey are presented as Exhibit A-12, Schedule 7. This table shows that the majority of jurisdictions have addressed LAUF gas costs by permitting GCR-type collection of these costs or tracking or true-up mechanisms. As Ms. Gardiner points out in her testimony, doing so is particularly appropriate where gas costs have increased substantially and become more volatile. Otherwise, the Company bears the financial risk associated with these market price movements.

LAUF gas associated with transportation gas is provided in kind. Adjustment clause treatment is common. Exhibit A-12, Schedule 7 attached to this testimony shows how LAUF gas costs are treated by many other utilities in many other jurisdictions.

I am aware that the Company's current tariff does not provide for the collection of LAUF gas costs in the GCR mechanism. I echo Ms. Gardiner and recommend that the tariff be modified to eliminate this exclusion or that a new parallel charge be instituted. The logic for collecting LAUF gas costs in the GCR is the same as

the logic for collecting any other gas cost in a gas cost adjustment charge. LAUF gas costs, similar to other gas costs, are a volatile variable cost, because those costs reflect the underlying market price of natural gas.

Failure to include LAUF gas costs in the GCR increases the "regulatory lag" in the recovery of these costs. In a rising price environment, it is likely that these costs will never be collected in full. In cases where the lag is significant, or if LAUF gas costs are not recovered, there is an increased need for cash to fund these costs, which results in increases in capital costs. Such cost increases accelerate the frequency of rate cases, which adds an additional layer of regulatory costs. In sum, not recovering LAUF gas costs in a timely manner, or at all, increases the total costs ultimately borne by customers.

Q. PLEASE DESCRIBE FURTHER THE BASIS FOR YOUR RECOMMENDATION WITH RESPECT TO THE COLLECTION OF LAUF GAS COSTS THROUGH THE GCR PROCESS.

A. This element of cost varies directly with the cost of gas, and all gas that is provided at the city gate is fungible. In other words, "LAUF gas" is physically indistinguishable from any other gas injected into the distribution system to be sold. In my view, customers should benefit promptly if this cost goes down because of market price movements, just as they do when other gas costs go down. For example, as is discussed in the testimony of Ms. Gardiner, over the past five years the percentage of gas lost on the Company's system was: 1.45% in

2001; 1.02% in 2002; 0.53% in 2003; 0.70% in 2004 and 0.65% in 2005. If the per unit cost of gas was constant over this time period, the actual per unit cost of LAUF gas to customers would have decreased, as the percentage of LAUF decreased. Under the current rate structure, where LAUF gas costs are recovered in base rates using a five-year average methodology, customers would not see the benefit of a reduced cost of LAUF gas until the next base rate case. In contrast, the Company's proposed treatment of these costs would insure that customers are only paying the actual cost of LAUF gas.

In addition, as pointed out by Ms. Gardiner, including the recovery of LAUF gas costs in the GCR process, in which gas cost prudence issues are addressed, should enable the Commission to monitor this element of the Company's gas costs just as it monitors the rest of the cost of gas. There is absolutely no logical reason for LAUF gas costs to be treated any differently than any other gas cost.

While the percentage that is attributed to LAUF gas is controlled, to some extent, by the Company,[23] the price of gas to which this percentage is applied is determined in the market, just like the price of the other gas that the Company buys on behalf of its customers.

Q. PLEASE CONTINUE.

[23] SEMCO Gas's LAUF percentage is low compared to other utilities, as described in Ms. Gardiner's testimony.

A. Let me address the regulatory lag that is inherent in the Commission's current ratemaking treatment of LAUF gas costs. To me, the regulatory lag under the current general ratemaking approach to these costs is no more reasonable than rate case treatment of other gas costs, which was abandoned long ago. General rate case treatment of these volatile, market-driven costs has been determined to be inefficient, e.g. the enactment of Act 304. Further, it is my opinion that the importance of the swings in revenue and earnings that this factor causes is magnified for smaller gas only utilities, such as SEMCO Gas. Even when LAUF volumes are managed well, under the current rate structure where LAUF gas costs are collected in base rates and not adjusted outside of the rate proceeding, the Company is at risk for over-or under-collection of LAUF costs based on the market price of gas. Ms. Gardiner illustrates this point using 2005 data. While LAUF gas volumes in 2005 were 457,606 Mcf, which is approximately the amount allowed in base rates, the market price for gas was significantly different than the gas price used to set the total LAUF gas expense in the rate proceeding. In 2005, the per unit price applied to LAUF was considerably higher than the price used to set the LAUF expense in base rates. As a result, the difference between the amount allowed in base rates for LAUF gas costs and the Company's actual experience was $ 867,243. This makes my point. As is pointed out by Ms. Gardiner, this is significant when it is compared to the Company's 2005 MPSC Division earnings of $9.3 million. From a ratemaking policy perspective, in my view, it is inappropriate for the Company's MPSC Division earnings to be affected so substantially by a change in LAUF gas costs caused by an increase in

the market price of natural gas. This is especially true when there are ratemaking methodologies for addressing this cost of service item that will match the Company's cost recovery and with the costs it actually incurs.

Q. IF THE COMMISSION DECIDES NOT TO APPROVE THE INCLUSION OF LAUF GAS COSTS IN THE COMPANY'S GCR RATE, THE COMPANY HAS SAID, IN MS. GARDINER'S TESTIMONY, THAT IT WOULD BE AMENABLE TO THE RECONCILIATION OF LAUF GAS COSTS USING AN ANNUAL TRUE-UP MECHANISM. PLEASE EXPLAIN HOW THAT MECHANISM WOULD WORK?

A. The annual true-up for LAUF gas costs would be an auditable mechanism that would be very similar to the GCR process. It would, however, be a separate mechanism and deal only with the LAUF portion of the Company's gas costs. Mr. Alger discusses this topic in more detail in his testimony.

<u>UNCOLLECTIBLE EXPENSE</u>

Q. WHY IS THE COMPANY PROPOSING TO ADJUST THE UNCOLLECTIBLE EXPENSE THROUGH AN ANNUAL TRUE-UP MECHANISM?

A. The logic for adjusting Uncollectible expense annually, to match the Company's actual cost for the commodity portion of this expense item, is similar to the rationale for addressing LAUF gas costs annually. The commodity costs associated with the Uncollectible expense fluctuate directly with the cost of gas.

When bills are high, two things happen: 1.) the bill becomes less affordable and thus more bills go unpaid; and 2.) the magnitude of the individual non payments is higher. Mechanisms to recover uncollectible expense in riders or in GCR-type clauses have been approved by regulators of several other LDCs, as summarized in Exhibit A-12, Schedule 7. Again, an important consideration in permitting such recoveries is what is going on in the marketplace, in terms of the absolute price for the commodity and price volatility.

Here, the Company is proposing to implement a true-up mechanism to adjust collection of total Uncollectible expense to the actually incurred expense on an annual basis. The Company's proposal in this regard is to true-up uncollectible expense in a fashion similar, but not identical to the approach that was recently approved for MichCon in the MPSC order in Case No. U-13898 and Case No. U-13899. I discuss this issue in more detail below.

Q. PLEASE EXPAND ON YOUR ANALYSIS OF UNCOLLECTIBLE EXPENSE AND ITS IMPACT ON THE COMPANY AND CUSTOMERS.

A. Similar to the process used to set the LAUF gas expense, under the current rate structure, the amount of Uncollectible expense the Company recovers is determined through a rate proceeding based on a review of historical Uncollectible expense. Once set, this amount is fixed in base rates. In periods of higher commodity prices, as have been experienced recently, monthly bills have become less affordable and result in increased Uncollectible expense. In

SEMCO' Gas's case, uncollectible expense in 2005 was $1,587,080, which substantially exceeded the 2004 uncollectible expense of $1,408,793, as explained by Ms. Gardiner. This issue was noted by the Michigan Public Service Commission in MichCon's 2003 rate proceeding Case No. U-13898; and Case No. U-13899:

> Many factors affect uncollectible expense, including the state's economy, the price of natural gas, the absolute total amount of customer billings, and the amount of state and federal aid that is available for heating assistance. Of these factors, the single largest influence on uncollectible expense is the cost of natural gas, which has been increasing significantly during the immediate past. The high price of natural gas, when coupled with reductions in government funding available to MichCon's low-income customers and the significant unemployment level in MichCon's service territories, has resulted in a large increase in uncollectible accounts. These factors are largely beyond MichCon's control.

In that proceeding, the Commission approved MichCon's request for an Uncollectible expense true-up mechanism, to allow MichCon the opportunity to recover the actual costs of Uncollectible expense by annually truing-up the Uncollectible expense included in base rates.

In markets where the price of gas is rising, it is likely that Uncollectible expense will be higher than the cost that was included in base rates. In SEMCO Gas's last base rate case, the allowance for Uncollectible expense filed for was $1,431,239 based on a $7.14/Mcf cost of gas. The Company's gas costs ranged between $6.3797 and $11.2684/Mcf in 2005. This means that the Company will not recover the full costs that are incurred for this expense item, thereby effectively

reducing its achieved rate of return. Also, as Ms. Gardiner notes in her testimony, Uncollectible expense also is affected by Commission policies. During this past winter heating season (through March 31, 2006), all arrears rose to $4,230,605 for SEMCO Gas because of the Commission's emergency regulations and the higher cost of gas. The Company had no control over these factors.

Conversely, if the Uncollectible expense is established using a history of high gas prices, it is possible that Uncollectible expense will decline, and customers will have over-contributed to this expense. Given the nature of this cost of service item, in my opinion, there is no rational basis for causing the Company to profit or incur losses – or for customers to over-compensate or under-compensate the Company – for this expense. In my view, it is a reasonable exercise of the Commission's ratemaking discretion to allow for recovery of Uncollectible expense through an annual true-up mechanism.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF MICHCON'S UETM TRUE-UP MECHANISM.

A. In a recent rate case,[24] the MPSC approved MichCon's proposed Uncollectible Expense Tracking Mechanism ("UETM") and allowed MichCon recovery of 90% of its actual Uncollectible expense. In that particular proceeding, participants in the case acknowledged that MichCon's Uncollectible expense was related to exogenous factors and was out of the control of the utility. Therefore,

[24] Case No. U-13898, Order dated April 28, 2005.

in addition to the Uncollectible expense that was included in base rates, the MPSC approved a UETM, which is a mechanism that reconciles actual Uncollectible expense over a 12-month period with the level of Uncollectible expense that was established as part of the Company's revenue requirement.[25] The mechanism is used to refund amounts to customers, in the event of an over-recovery, or to assess a surcharge to recover under-recovered Uncollectible expense.

Q. DOES THE COMPANY PROPOSE TO ADOPT THIS MECHANISM?

A. Conceptually, the approach that is proposed by the company is similar to what has been approved for MichCon. However, it is my understanding that MichCon was only granted 90% recovery of uncollectible expenses because the commission found MichCon's poor collection policies to be inadequate. SEMCO has been very effective collection policy, as is discussed by Mr. Dubay. Therefore, SEMCO is seeking and should be allowed to recover its full uncollectible expense.

ACCELERATED PIPELINE REPLACEMENT PROGRAM

Q. YOU INDICATED THAT THE COMPANY IS PROPOSING AN ACCELERATED REPLACEMENT PROGRAM ("ARP") TO COPE WITH NEEDED BUT EXTRAORDINARY NON-REVENUE PRODUCING CAPITAL EXPENDITURES. PLEASE EXPLAIN WHY SUCH A PROGRAM IS NECESSARY.

[25] MichCon is at risk for 10% of the uncollectible expenses under this program.

A. The proposed ARP is necessary to allow the Company to address an unusual situation, as explained by Company witness Larsen. The characteristics of the program that make the ARP appropriate, as contrasted with typical rate base treatment, include: (1) the expenditures are large[26] because the program calls for accelerated capital expenditures in order to continue to provide safe and reliable service; (2) these capital expenditures should reduce O&M costs associated with old plant (including bare steel pipe that was installed decades ago and is becoming increasingly corroded and prone to leakage problems);[27] (3) because of the size and nature of the expenditures, the Company would be harmed by the normal regulatory lag associated with incurring these capital costs and asking that they be included in rate base; (4) the investments covered by the ARP are non revenue producing plant additions; and (5) this proposal is consistent with various rate design and revenue collection mechanisms proposed in this case, which together should help limit the number and frequency of future base rate proceedings to a reasonable level and thus save customers the costs associated with those proceedings. If these capital projects are undertaken in the absence of the proposed ARP, the Company will likely be forced to come before the Commission frequently over the course of the next 10-12 years, simply to ensure the timely inclusion of these items in rate base.

[26] Mr. Larsen has estimated annual expenditures of $5 million for the proposed 15 year program.

[27] As Mr. Larsen explains, as time passes unprotected steel pipe begins to leak more and more because a geometrically increasing percentage of the walls of the pipe are subject to penetration as the result of cumulative corrosion over the years. This can develop into a hazardous situation with out constant vigilance and an ever increasing number of leak repairs. The only practical solution is a systematic program to replace bare steel pipe.

Q. CAN YOU DISCUSS FURTHER THE REASON WHY THE PROPOSED PROGRAM IS APPROPRIATE IN THE CONTEXT OF MICHIGAN REGULATION?

A. Yes. One of the problems that the Company faces is that the pipe replacement program encompasses several discrete elements of construction with no single element of the program spanning more than six months. This means that the projects within the program do not qualify for AFUDC treatment, and, in a sense, the Company's ARP, which is intended to allow the Company to recover the capital-related costs on these investments between rate cases, is a substitute for that treatment. Once again, the Company is faced with a dilemma. Because of its relatively small size, the Company cannot afford to undertake the necessary program investment without timely rate relief. One of the overriding themes of SEMCO Gas's filing in this case is to provide the Company with a fair opportunity to earn the return that the Commission has found to be just and reasonable. The choice with respect to these investments is to file for rate relief every year or develop a program that will allow for complete regulatory monitoring and auditing, but without the necessity of rate filings seriatim. One of the key advantages of the rate proposals set forth previously in this testimony and the testimony of Ms. Gardiner and others is to reduce regulatory burden and cost.

Q. HAVE ACCELLERATED REPLACEMENT PROGRAMS BEEN IMPLEMENTED IN OTHER JURISDICTIONS?

A. Yes. The problem of old and deteriorating natural gas distribution system infrastructure made of wood, cast iron, wrought iron and unprotected steel is a common issue that has been addressed by numerous jurisdictions. Many of these jurisdictions have programs to accelerate replacement of key system components in the interest of safety and the early realization of reduced O&M costs. Summaries of several of these programs are presented in Exhibit A-12, Schedule 8.

THE COST OF SERVICE STUDY

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY ("COSS")?

A. The purpose of the COSS is to provide an accurate measure of the cost responsibility of each of the Company's rate classes based on cost causation principles. The COSS measures the Company's revenues, costs and profitability by customer class. As noted earlier, the analysis of Company financial and cost data that is performed includes three steps: functionalization; classification; and allocation. In general, costs are grouped based on the function for which they are incurred. Costs are divided based on customer, demand, and commodity classifications. Finally, the costs are assigned or allocated to the customer various classes. The result of the study is a detailed breakdown of the costs of serving each customer class. This approach provides the objective basis for rate setting, allowing costs to be recovered from customers based on their use of the various resources required to provide service to them. From a big picture viewpoint, a

properly conducted COSS provides a rational basis for the Commission's ratemaking judgments.

Q. PLEASE DISCUSS THE RESULTS OF THE COMPANY'S COSS.

A. Exhibit A-11, Schedule F-6 includes the results of the Company's COSS with various known and measurable changes (the fully adjusted or 2007 test year). The results with respect to class return on rate base are shown on the page 9 (also labeled Earned Return Summary) in the Cost of Service study. The class returns are in a relatively narrow range compared to some utilities for which I have worked. Pages 3 through 8 of Exhibit A-11, Schedule F-6 show the unitized costs. This report sums up the fixed cost in the per Customer spread sheet on page 7 of 13. It shows that the fixed cost including the Customer-related piece and the Demand-related piece sum to $24.09 per residential customer per month. This does not include the LAUF gas expense, which SEMCO Gas proposes to collect in the GCR. If the Commission were to reject the Company's LAUF gas cost recovery proposals, the service charge amount would be $25.18 per residential customer per month.

The proposed fixed service charge rate will exactly equal the sum of the customer charge and the revenue collected through the volumetric charge at the average consumption level. The volumes and revenue requirements can be found in the Cost of Service study Exhibit A-11, Schedule F-6, under the "Revenue Requirement Summary" and subsequent unit cost calculation pages. In this case

the implied volumetric charge if the customer charge were fixed at the current $9.50 is $0.17860/ccf. If the comparison is thus made to the current structure, the proposed $25.18 fixed monthly Service Charge (including LAUF) would be compared to $9.50 Plus ($0.17860 x (23,531,876 Mcf/223,383 customers = 105.343 Mcf / year / 12months = 8.77859 Mcf/month or 87.786 ccf/month) = $15.68) = $25.18. Thus, the proposed fixed monthly service charge exactly equals the sum of the customer charge and what the volumetric charge would have been under the old rate structure at the average monthly consumption.

Q. PLEASE EXPLAIN HOW THE COSS WAS CONDUCTED.

A. The analytical process used for the COSS is consistent with the process used by the MPSC Staff and the Company, and approved by the MPSC, in prior rate proceedings. The analysis is facilitated by a cost study model that was prepared by CEA. The model is provided in Exhibit A-6, Schedule F-6, and Exhibit A-11, Schedule F-6. The following steps outline the process used to develop the COSS:

Functionalization - Plant investment costs are categorized by the operational functions with which they are most closely associated. These functions include production, purchased gas, storage, distribution, and customer services. Administrative and General Costs must be functionalized to these categories depending on the purpose of the sub-accounts (i.e. what function they support).

Classification - The functionalized costs are classified by the utilization of categories that most closely match the purpose for which the cost was incurred or to which the cost is most directly correlated (i.e., to meet maximum demand, to serve each customer and to supply the commodity). The criteria used to identify the most appropriate factors were as follows:

i. *Demand costs* are costs that are independent of hour-to-hour changes in throughput, but are related to peak requirements. SEMCO Gas has traditionally used a Peak and Average allocator for demand-related costs which as I understand, the Staff has expressed a preference for in the past, and which I am using in the interest of continuity.

ii. *Customer costs* are those costs that are required to provide service to a customer, independent of throughput or peak demand. Meters and customer billing are examples of such costs.

iii. *Commodity costs* are those costs that are dependent on throughput. Gas cost is the primary example.

Allocation - In the allocation process, the determinants or cost causing factors of the specific investments or costs are identified and developed by class. Next, these costs or investments are assigned to customer classes based on internally or externally derived allocation factors. Internally derived factors were developed based on directly assigned costs and are used to allocate general costs such as general plant or administrative and general costs. Externally derived factors were based on data such as the commodity use by class, the peak demand by class, the

number of customers, revenue by class, and the like. Costs were allocated appropriately among the Company's utility operations.

Q. WHAT IS THE SOURCE OF THE DATA USED IN THE STUDY?

A. The cost and revenue data for the COSS was provided by the Company and is derived from the Company's annual filing and the required rate case filing exhibits. Known and measurable cost calculations are shown in the exhibits sponsored by Dr. Fairchild, Mr. Alger, and Mr. Warsinske. Therefore, the study reflects the expected cost of operations for the historical period ended December 31, 2005, as adjusted to reflect known and measurable and other appropriate changes to that historical data. The goal is to present cost data that is representative of the rate effective period.

Q. WHAT IS THE ASSUMED COST OF CAPITAL IN THE STUDY?

A. The COSS relies on an 11.9% Return on Equity and the overall cost of capital that was determined by Company witness Fairchild.

Q. HOW IS THE REVENUE REQUIREMENT DETERMINED?

A. The total revenue requirement is computed as the sum of total operating expenses and total expected return on rate base, as adjusted for income taxes. Review of the 2007 test year costs and revenues indicates that on a system-wide basis, the Company's total revenues are projected to be $391.4 million. The net operating income to the Company for this test year is $16.9 million. Rate base for the 2007

test year would be $346.0 million. Assuming a rate of return of 8.23%, the revenue requirement is $105.3 million excluding the cost of gas which means there is a revenue requirement shortfall of $18.1 million.

Q. HOW WOULD THE COMPANY COLLECT ITS REVENUE REQUIREMENT IF THERE WERE NO CHANGE IN RATE DESIGN?

A. Absent any changes in rate design, the Company would continue to collect its revenue requirement through a three-part rate consisting of a fixed customer charge, a volumetric delivery charge, and a GCR charge for all classes of customers. To the extent that actual consumption is less than the forecast of consumption that is used to establish the volumetric distribution charge, the Company would not recover its allowed revenue requirement. If the Commission chooses not to adopt the Company's proposed rate design changes, based on the trend of declining usage per customer, I recommend that a use per customer based on a projected continuation of this trend be used to determine rates. If the Company's proposals are adopted, use of this sort of trended figure this will not be necessary to ensure that the Company has a fair opportunity to recoup its costs of providing service to customers.

<u>WEATHER NORMALIZATION</u>

Q. WHAT SHOULD THE COMPANY USE TO DEVELOP THE TREND FOR WEATHER NORMALIZED CUSTOMER CONSUMPTION?

A. Again, if the Company's proposed fixed monthly service charge rate design is adopted, how best to weather-normalize consumption data is not an issue. If, however, the current rate design continues to be used, the rates should be established based on billing determinants that can actually be achieved in order to allow the Company the ability to recover the full revenue requirement. Therefore, the Company should be allowed to rely upon a 15-year weather data set rather than the 30-year data set that has been relied upon in the past. This issue has been addressed by SEMCO Gas in the past, and, in my opinion, solid and robust evidence was submitted by SEMCO Gas witness Laderoute in November 2002 that demonstrated that the 15-year data set produced a better result from a statistical point of view than the 30 year data set.

Q. IN YOUR EXPERIENCE, IS THIS AN ISSUE THAT IS FREQUENTLY RAISED IN REGULATORY PROCEEDINGS?

A. Yes. How to normalize customer consumption data is frequently an issue in regulatory proceedings. Mr. Laderoute presented evidence indicating fifteen companies throughout the country use 20 or less years of historical degree day data to normalize sales for weather. In addition to the examples that were provided by Mr. Laderoute, I am aware of several other utilities that rely on less than 30 years of historical degree day data to normalize sales for weather. Exhibit A-12, Schedule 9 identifies these utilities.

Q. HAVE THE UTILITIES LISTED IN EXHIBIT A-12, SCHEDULE 9 ALWAYS RELIED ON SHORTER DATA SETS?

A. No, not generally. Recently, utilities have been seeking the use of shorter time periods for the normalization calculation. In many cases, in response, regulatory agencies move from 30-year normalization calculations to normalizations based on considerably shorter time periods. For example, in Wisconsin, the Public Service Commission has moved to 20-year weather normalization for all gas companies in the state. In Rhode Island, the standard used to be based on a 30-year data set as well. In its most recent rate proceeding, however, New England Gas was permitted to charge rates based on a 15-year weather normalization for its ProvGas subsidiary.

RATE ELEMENTS

Q. HOW DOES THE COMPANY PROPOSE TO COLLECT ITS REVENUE REQUIREMENT?

A. As has been discussed previously, the Company is proposing a new rate structure for the residential class; namely, a fixed monthly service charge, a volumetric charge for costs recovered through the GCR and a net "true-up" charge for certain other costs. The variable distribution charge would be eliminated. The fixed monthly service charge of $24.09 (without LAUF) is structured to recover the fixed costs of providing service to the Company's residential customers. The variable component of the residential rates would be comprised of current GCR mechanism costs, including the proposed collection of LAUF gas costs. In

addition, a flat aggregate net true-up charge would be assessed to collect or provide credits for the true-up of Uncollectible expense, the ARP, and conservation program costs.

The Company is not proposing to change the underlying rate structure for all other rate classes. Instead, for non-residential customer classes, the Company is proposing modest increases to customer charges, but primarily relatively modest adjustments (up or down) for these classes to fully recover the cost of service in accordance with the Cost of Service study results. The Mead rate will have to be kept constant in-as-much as it is a contract rate and thus the Company would propose to collect the cost of service shortfall from the other classes in proportions determined by the Commission.

Q. PLEASE DESCRIBE THE RATE DESIGN COMPARISONS THAT YOU SHOW ON EXHIBIT A-11 SCHEDULES F-1, ET SEQ.

A. Exhibit A-11 provides a comparison of the current and proposed rates for each class of service. Schedule F-1 provides a comparison of the current and proposed revenues by class. Column A of this schedule shows the revenues that would be generated by class under the current rate schedule, assuming the test period number of customers and throughput levels. As is indicated in this schedule, the total revenue that would be collected from both sales and transportation customers under the current rate structure and the test period assumptions of customers and volume would be $79,972,076. Column B is a summary of the revenues that

would be collected under the proposed rates. The detailed calculations for each rate are provided in Schedule F-4. As is illustrated in Column B of Schedule F-1, the proposed rate structure would produce total revenue to the Company of $99,001,995, assuming the test year number of customers and throughput. The total revenue by class that is produced by the proposed rate design is equal to the total revenue requirement from rates that resulted from the Cost of Service Study. This can be verified by comparing Columns B and E of Schedule F-1.

The remaining columns in Schedule F-1 provide a comparison of the revenues generated by the current rates and proposed rates. Column C provides the total dollar increases by class, while Column D provides the increased revenue requirements as a percentage of total gas and distribution costs.

In addition to the total revenues by class, Schedule F-1 compares the current and proposed unitized rates. As is illustrated in the Average Rate Comparison section of this schedule, on a percentage basis the proposed increase in distribution rates is relatively small; less than 5% of the total customer bill for all customer classes.

Q. PLEASE EXPLAIN WHY THERE IS A DIFFERENCE BETWEEN THE "CURRENT REVENUES" IN EXHIBIT A-11, SCHEDULE F-1 AND THE 2007 NORMALIZED REVENUES IN EXHIBIT A-11, SCHEDULE F-3 THAT WAS SUBMITTED BY MR. ALGER.

A. The difference between these two calculations is that Schedule F-3 reflects actual adjusted revenues based on customer migration, consumption, and rate timing differences while Schedule F-1 produces theoretical maximum revenue based on the static test period annual throughput and average customers for each class. In Schedule F-1, the Current Revenues that are calculated are the revenues that could be generated based on the test period throughput levels and number of customers. In Schedule F-3, the revenues that are calculated are based on the actual throughput and rate adjustments that have occurred in the test period.

Q. PLEASE EXPLAIN SCHEDULES F-4 AND F-5.

A. As I mentioned previously. Schedule F-4 calculates rates that will produce the revenue requirement that was derived in the COSS for each class. In addition, Schedule F-4 compares the proposed revenue requirement to the revenue that would be produced by the current rates under the same customer and volume assumptions. For example, page 1 of Schedule F-4 shows the calculation of the proposed residential rate. In this schedule Column A provides the throughput and customer assumptions. Column B shows the Current Rate and Column C provides a Pro Forma Revenue based on the current rates and revenues. Under the current rates, the Residential class would contribute $54,245,146 to the revenue requirement. Columns D & E provide the proposed rate and the resulting revenue from the proposed rates. Under the proposed rate structure, the Residential Service Charge would provide $64,570,511 of the revenue requirement and the LAUF rate would provide $2,924,022 for a total residential contribution to

revenue of $67,494,533 or a $13,249,387 increase in the residential revenue requirement for the distribution rate. As is shown in Schedule F-1, on an annual basis, as a percentage of the total residential customer revenue requirement, including gas costs[28], the proposed rate change is an increase of 4.15 %. The remainder of Schedule F-4 relies on the same methodology to calculate the proposed rates for the general service and transportation customer classes and provides the same comparison of proposed and current rates.

Finally, Schedule F-5 provides a comparison of the current and proposed rates on a unitized basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

[28] Assuming gas cost of $11.2684 per Mcf.

Bibliography

1. "Joint Statement of the American Gas Association and the Natural Resources Defense Council" July 2004.

2. Costello,Ken. "Revenue Decoupling for Natural Gas Utilities", The National Regulatory Research Institute, April 2006

3. Kitts, Gary. "Energy Efficiency Programs", Michigan Public Service Commission, Staff Report, January 31, 2006.

4. Kahn, Alfred E., The Economics of Regulation; Principles and Institutions, Volume I, John Wiley & Sons, Inc. New York, 1970

5. Martin Kushler, Ph.D., Dan York, Ph. D, and Patti Witte, M.A. , Examining the Potential for Energy Efficiency To Help address the Natural Gas Crisis in the Midwest, American Council for an Energy-Efficient Economy, Washington, D.C. January 2005.

Malcolm R. Ketchum
Vice President

Mr. Ketchum is a management and regulatory economics consultant with more than 25 years of experience as a regulator, utility officer, and management consultant executive. He has an extensive background in the areas of ratemaking and regulatory policy, energy market assessment, resource procurement and contracting, valuation, strategic planning and organizational matters. Mr. Ketchum has provided expert testimony on more than 100 occasions before the Federal Energy Regulatory Commission, the National Energy Board of Canada, state utility regulatory agencies, and state courts in civil proceedings.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis, Ratemaking and Restructuring

Mr. Ketchum provided advisory and expert witness services to natural gas and combination utilities, gas pipelines, gas producers, water, and electric utilities (Such as GPU-now FirstEnergy-, Delmarva Power-now Conectiv-, Southern Union Gas, Alliance Pipeline, and the Canadian Association of Petroleum Producers) throughout North America. He provided services relating to regulatory policy analysis and formulation across a broad spectrum of issues, including energy industry restructuring, rate unbundling, cost of service, cost of capital as well as virtually all aspects of utility ratemaking. In many instances, services have included the provision of expert testimony before the Federal Energy Regulatory Commission and state regulatory agencies.

Played a major role in the restructuring of the services of many natural gas and electric utility companies during the past 15 years, beginning with restructuring the services of Southern Union Gas in 1986. Worked on all aspects of the restructuring process including strategic and business unit planning, merchant function exit strategies, stranded cost assessment, residual merchant service obligation assessment and planning, tariff design, development of new services, pricing, market analysis, organizational issues and regulatory policy. Clients have included: Brooklyn Union Gas, Wisconsin Gas, Piedmont Natural Gas, Southern Connecticut Gas, EnergyNorth Natural Gas, Delmarva Power and Light, New Brunswick Power, and Public Service of Oklahoma.

Repeatedly retained by numerous utilities to provide a wide spectrum of ratemaking services including preparation of cost of service studies, marginal cost studies, inflation forecasts, cost of capital studies, rate design, drafting of tariff provisions. Developed PC-based studies on behalf of clients, trained client staff, and transferred such studies to clients for future use. Services provided also include virtually all aspects of rate design including tariff design, and load research. Extensive support provided in the area of performance-based ratemaking (PBR) both for base rates and fuel and contract costs (e.g., gas costs, power purchase agreements). Support provided includes development and assessment of PBR options, design of PBR proposal, and regulatory support. Clients have included the City of Richmond Department of Public Utilities (Water, Wastewater, Electric, and Gas), Midwest Gas and the Northern Natural Distributor Group.

Litigation Support and Expert Testimony

Provided expert testimony and litigation support on more than 100 occasions to numerous energy industry participants throughout North America in administrative and civil proceedings on a variety of energy and economic issues. Represented gas distribution utilities, electric utilities, energy producers, gas pipelines, and regulatory agencies, and industry associations as an expert witness before the Federal Energy Regulatory Commission, the National Energy Board of Canada, state utility regulatory agencies, and state courts in civil proceedings. Testified on issues ranging from broad regulatory and economic policy to the detailed elements of utility ratemaking. Examples of testimony include: regulatory policy, pricing, revenue requirements, energy contract interpretation, fuel procurement practices, management prudence, income tax allowances, tariff structure and language, cost of capital, performance-based ratemaking, cost of service, rate design, and marginal cost analysis, attrition of earnings, and market analysis. In addition to developing and sponsoring expert testimony, specific services provided include collaborating with counsel as well as business and technical staff to clients to develop litigation strategies, prepare and review discovery and briefing materials, preparing materials and participating in formal and informal meetings with regulators and intervenors.

Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to provide assessments of regional energy markets. Specific services include: performance of market power analyses in support of market-based rate applications; acted as key investigator of the marginal costs of providing electric power for a Caribbean Island electric system of the World Bank; developed shadow exchange rate estimates for foreign components of investment. Specific clients include; Alliance Pipeline, Canadian Association of Petroleum Producers, World Bank, Barbados Light and Power, and New Brunswick Power.

Resource Procurement, Contracting and Analysis

On behalf of natural gas local distribution companies (LDCs), gas pipelines, gas producers, electric utilities, and independent energy project developers nationwide, personally negotiated dozens of energy-related contracts. Contract types negotiated, analyzed or reviewed include energy sales, transportation, gas purchase, operations and maintenance (O&M) and labor contracts. Reviewed, analyzed and made recommendations regarding hundreds of gas supply contracts on behalf of LDC group and regulators. Specific clients have included; Southern Union Gas Co., Western Gas Interstate, Missouri Gas Energy, Geneva Steel, EnergyNorth, and EOC/EPNG distributor group.

Business Strategy and Operations

Retained by numerous leading energy companies and financial institutions nationwide to provide services relating to the development of organizational studies and strategic plans and planning processes for both regulated and non-regulated enterprises. Services provided include; project management, organizational studies, departmental restructuring, budgeting, and development of business plans and corporate strategic plans. Samples of specific project experiences include: developed an energy service company business plan for a new subsidiary of a major energy company; served as project manager for a comprehensive organizational review of a Midwestern electric utility; performed interviews, evaluated job descriptions, reviewed reporting relationships and span of control, developed personnel profiles, redesigned organization charts, and prepared comprehensive organizational restructuring report.

Specific clients have included: The City of Richmond Department of Public Utilities, Kennebec Water District, Midwest Energy, Southern Union Gas Co., and Brooklyn Union Gas Co.

PROFESSIONAL HISTORY

Concentric Energy Advisors (2002 – Present)
Vice President

Ketchum Properties (1998-2002)
President, Investor

Navigant Consulting, Inc. (1997 - 1998)
Executive Vice President

REED Consulting Group (1990 - 1997)
Executive Vice President and Principal

Southern Union Gas Company (1984 - 1990)
Vice President, Rates and Regulatory Affairs (1988 – 1990))
Director, Rates and Regulatory Affairs (1984 – 1988)

R.J. Rudden Associates, Inc. (1983 - 1984)
Vice President

Stone & Webster Management Consultants, Inc. (1976 - 1983)
Vice President (1981 – 1983)
Assistant Vice President (1980 – 1981)
Senior Consultant (1976 – 1980)

EDUCATION

Masters Program in Minerals & Energy Resources, University of Texas, 1989
NARUC Regulatory Studies Program, Michigan State University, 1974
Albany Law School, 1972 – 1973
BA, Economics, State University of New York at Binghamton, 1968
AA, Liberal Arts, Broome Technical Community College, 1966

BOARDS OF DIRECTORS

REED Consulting Group (1990-1998)
Southern Union Employees Credit Union (1988-1990)
Northwood Water District (1972-1974)

PUBLICATIONS/PRESENTATIONS

Mr. Ketchum has made presentations throughout North America regarding the energy industry restructuring, rate unbundling, marginal cost pricing and incentive ratemaking at energy industry seminars, management training courses, and regulatory conferences.

AVAILABLE UPON REQUEST

Extensive client and project listings, as well as specific references provided on request.

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
FEDERAL/NATIONAL JURISDICTIONS:					
Federal Energy Regulatory Commission	2003	Indicated Shippers	Northern Natural Gas Company	RP03-398-000	Allocation of System Balancing Costs, Rate Seasonality, Term Differentiated Rates, Interruptible Rate Design
	1996	Canadian Assoc. of Petroleum Producers	Northwest Border Pipeline	RP95-409-000	Cost of Capital
	1996	Canadian Assoc. of Petroleum Producers	Northwest Border Pipeline (Rebuttal)	RP96-45	Cost of Service
	1996	Canadian Assoc. of Petroleum Producers	Northwest Border Pipeline (Direct)	RP96-45	Cost of Service
	1994	Missouri Gas Energy	KansOk Partnership	RP94-3-000	Revenue Requirements, Throughput, Cost of Service, Rate Design, Cost of Capital
	1994	Missouri Gas Energy	Williams Natural Gas	93-109-000	Cost of Service, Rate Design
	1994	Canadian Assoc. of Petroleum Producers	Lakehead Pipeline	IS93-33-000 and IS92-27-000	Cost of Capital
	1993	Western Gas Interstate	Western Gas Interstate	RP93-40-000	Tariff Changes, Cost of Capital
	1992	Generic Rulemaking	Northern Distributor Group	PL92-1-000	Incentive Ratemaking Comments Filed
	1992	Questar Pipeline	Geneva Steel	RP91-140-000	Cost of Capital, Rate Base, Cost of Service, Rate Design
National Energy Board of Canada	1998	Alliance Pipeline Project	Alliance Pipeline	GH-3-97	Market for Canadian Gas – East of Rocky Mountains

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
STATE/PROVINCIAL JURISDICTIONS:					
Alberta Energy and Utilities Board	2003	City of Calgary	ATCO Electric and ATCO Gas	Application to Transfer Retail Functions	Functional Separation Competitive Markets, Affiliate Code of Conduct
Arizona Corp. Commission	1990	Southern Union	Southern Union	ACCU-1240-90-051	Cost of Service, Rate Design, Loss Factors, New Area Development
	1988	Southern Union	Southern Union	1988 Rate Case	Cost of Service, Rate Design
Austin City Council	1987	Southern Union	Southern Union	1987 Rate Case	Rate Design, Revenue Requirements
	1985	Southern Union	Southern Union	1985 Rate Case	Cost of Service, Rate Design, Revenue Requirements
Connecticut Dept. of Public Utility Control	1998	Southern Conn. Gas	Financial and Operations Review	97-12-21	Exiting the Merchant Function
	1997	Southern Conn. Gas	Generic Unbundling Investigation	97-07-11	Unbundling Natural Gas Service
	1995	Southern Conn. Gas	So. Conn. Gas Rate Case (Reopened)	93-03-09	Unbundling of Rates, Cost of Service, New Service Offerings
	1995	Southern Conn. Gas	Generic Review of Cost of Service	94-11-12	Unbundling of Rates, Cost of Service, New Service Offerings
Delaware Public Service Commission	1995	Delmarva Power & Light	Delmarva Power & Light	1995 Unbundling of Rates	Transportation Rates, Gas Cost Adjustment Clause, New Service Offerings
	1992	Delmarva Power & Light	Delmarva Power & Light	91-24 (1991 Rate Case)	Cost of Service, Rate Design, Transportation Rate Policy
El Paso Texas Public Utility Regulation Board	1990	Southern Union	Southern Union	1990 Rate Filing	Rate Design
	1985	Southern Union	Southern Union	1985 Rate Filing	Cost of Service, Rate Design
Florida Public Service Commission	1996 – 1997	Associated Gas Distributors of Florida	Natural Gas Unbundling Workshops	RP96-0725066	Unbundling LDC Services
Georgia Public Service Commission	2004	Atlanta Gas Light Company	Atlanta Gas Light Company	18638-U	Allocated Cost of Service

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
Iowa Utilities Board	1995	Midwest Gas, Division of MidAmerican Energy	Midwest Gas	RPU94-3	Incentive Gas Procurement Plan
Kansas Corporation Commission	1994	Missouri Gas Energy	Kansas Natural Partnership/Kansas Pipeline Partnership	190, 362-U	Pipeline Revenue Requirements
	1982	Kansas Power & Light	Kansas Power & Light	115.379.4	Regulatory Standards
Massachusetts Department of Public Utilities	1996	Essex County Gas	Essex County Gas	96-70	Marginal Costs, Rate Design, Unbundled Rates
	1993	Essex County Gas	Essex County Gas	93-107	Marginal Costs, Rate Design
	1979 - 1980	Eastern Utilities	Eastern Utilities	3243, 837, and 1130	Earnings Attrition
Montana Public Service Commission	1979 - 1980	Montana Dakota Utilities	Montana Dakota Utilities	6567 and 81.1.1 (Phase II)	Marginal Costs
Nevada Public Service Commission	1991	Southwest Gas Corp.	Southwest Gas Corp.	90-1109/90-1110	Gas Supply Costs
Board of Commissioners of Public Utilities of New Brunswick	2005	New Brunswick Power Distribution & Customer Service Corp.	New Brunswick Power Distribution & Customer Service Corp.	Board Reference 2005-002	Class Cost of Service and Rate Design
New Hampshire Public Service Commission	1993	EnergyNorth Natural Gas, Inc.	EnergyNorth	DR93-030	Natural Gas Vehicles Rate
	1992	EnergyNorth Natural Gas, Inc.	Generic Transportation Proceeding	DE91-149	Gas Transportation Issues
	1992	EnergyNorth Natural Gas, Inc.	EnergyNorth	DR91-212	Marginal Costs, Rate Design
	1992	EnergyNorth Natural Gas, Inc.	EnergyNorth	DR90-183	Marginal Costs, Embedded Cost of Service, Rate Design, Tariff Issues
	1983	Manchester Gas Company	Manchester Gas	DR81-234	Cost Analysis
New Jersey Public Service Commission	1998	Jersey Central Power & Light	JCP&L	E97070458	Electric Rate Restructuring and Service Unbundling
	1996	South Jersey Gas Company	South Jersey Gas	GR96010032	Cost of Service

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Mexico Public Service Commission	1983	El Paso Electric Co.	El Paso Electric Co.	????	Time of Day Rate Impact
	1982	El Paso Electric Co.	El Paso Electric Co.	Case #1454 and Case #1530, II	Marginal Costs
New York Public Service Commission	1971 - 1976	NYPSC Staff (Mr. Ketchum was a member of the NYPSC Staff during this time)	Consolidated Edison, Long Island Lighting, Rochester Gas & Electric, New York Telephone, Western Union, Rochester Telephone	12 Cases	Testified on a variety of issues across cases: wage rates, inflation impact, demand forecasts, area economics, econometric analysis, price elasticity, cost/benefit analyses
North Carolina Utilities Commission	1994	Piedmont Natural Gas	Piedmont Natural Gas	G-9, SUB351	Rate Unbundling, Transportation Rates, Rate Design
Oklahoma Corporation Commission	1988	Southern Union Gas	Southern Union Gas	PUD Case No. 0385	Rate Design, Revenue Deficiency
Pennsylvania Public Utility Commission	1998	GPU Energy	Penelec	R-00974009	Electric Rate Restructuring and Unbundling
	1998	GPU Energy	MetEd	R-00974008	Electric Rate Restructuring and Unbundling
Railroad Commission of Texas	1987 – 1988	Southern Union Gas	Southern Union Gas	5238	Revenue Deficiency, Cost of Service, Rate Design
	1985	Southern Union Gas	Southern Union Gas	5238	Gas Supply Charges
Rhode Island Public Utilities	1993	Valley Gas Company	Valley Gas	2138	Rate Design
	1979 - 1980	Eastern Utilities Associates	Eastern Utilities	1439, 1184, 1185, and 1701	Earnings Attrition
South Dakota Public Utilities	1995	MidWest Gas, Division of MidAmerican Energy	MidWest Gas	NG95-006	Incentive Gas Procurement Plan
	1982	Montana Dakota Utilities	Montana Dakota Utilities	Docket No. F-3153 and Case 10,223	Marginal Costs

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
Tennessee Public Service Commission	1994	Nashville Gas Co.	Nashville Gas Co.	94-01054	Service Unbundling, Transportation, Rate Design
Texas Public Utilities Commission	1990	PUC General Counsel	Texas Utilities Electric	9300	Gas Purchasing Practices
	1982	El Paso Electric Co.	El Paso Electric Co.	1776 and 3437	Rate Design, Cost of Service, Marginal Costs
Utah Public Service Commission	1992	Geneva Steel	Mountain Fuel Supply Co.	91-057-11 and 91-057-17	Gas Supply Costs
Virginia State Corporation Commission	2005	Virginia Natural Gas, Inc.	General Rate Case Filing of Virginia Natural Gas, Inc.	Case No. PUE-2005-00062	Jurisdictional and Class Cost of Service Study

MALCOLM R. KETCHUM
EXPERT TESTIMONY

JURISDICTION	DATE	SPONSOR	CASE/APPLICANT	DOCKET NO.	SUBJECT
LOCAL JURISDICTIONS & CIVIL PROCEEDINGS					
District Court of Hutchinson County, Texas	1985	Western Gas Interstate	Western Gas Interstate	Civil Action 2-8-84	Gas Supply Issues
Various Texas City Councils	1985 - 1990	Various Local Jurisdictions served by Southern Union Gas	Southern Union Gas	City Council Meetings (17 Cases) And Rate Case Presentations	Revenue Requirements, Cost of Service, Cost of Capital, Rate Design

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF RICK L. AYERS

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony Of Rick L. Ayers
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is Rick Ayers, and my business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position with that employer?

A. My title is Director of Information Technology for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company").

Q. Please describe your academic background and business experience.

A. In 1993, I graduated from Walsh College of Accountancy and Business Administration, Troy, Michigan, with a Bachelor's degree in Business Administration. In my current position, I oversee information technology projects and planning activities for the Company. I have held positions of increasing responsibility at SEMCO Gas since 1989, including positions in Information Technology, Training and Development, Customer Service and Planning. I held Director level positions in Customer Service and Planning for SEMCO Gas before moving to my current position. Prior to working for SEMCO Gas, I was employed by North American Benefit Association as an application programmer.

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

A. My testimony describes two new technology applications to be used to provide service to customers, explains why SEMCO Gas needs the new applications, and details the costs associated with the new applications.

Q. Have these new technology applications been approved by SEMCO Gas's Board of Directors?

A. Yes, the funding for these new technology applications has been approved by SEMCO Gas's Board of Directors.

Q. Does SEMCO Gas anticipate cost savings from the implementation of the new technology applications?

A. SEMCO Gas does not anticipate cost savings from the implementation of the new technology applications, through the time period reflected in this case, due to the costs associated with implementing and maintaining new technologies required by the applications, the costs associated with implementing new business processes, and the costs associated with training employees during this time period.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my direct supervision:

Exhibit A-12, Schedule 2, CIS System Implementation

Exhibit A-12, Schedule 3, FOS System Implementation

Q. Have you previously testified before the Michigan Public Service Commission?

A. Yes, I provided testimony on technology systems in MPSC Case Number U-14338.

<u>Customer Information System</u>

Q. What is the purpose of the Company's customer information system?

A. The Company's customer information system ("CIS") is a computerized system for handling all aspects of the Company-customer relationship. This includes (i) tracking basic customer account information (such as a

customer's name, service and billing addresses, account number, and rate classification), (ii) providing information from this computerized database to Customer Service Representatives, so that they can answer customer inquiries, (iii) creating work orders that cause Company personnel to provide various services for customers (such as installing new gas service lines or checking on suspected gas leaks), (iv) tracking customer gas consumption, (v) billing customers for their gas consumption and other services, and (vi) processing customer payments and providing the revenue data needed for the Company's books and records.

Q. Why is a new application necessary?

A. The Company's current CIS was originally installed over 25 years ago. That system was developed by SEMCO Gas itself to support customer service requirements at that time. Because this was the available technology at the time, the old CIS system was "hard coded" and therefore it is not a flexible, configurable system. Over the intervening years, the system has been modified from time-to-time, to reflect and support changes in processes that were either required by tariff or needed to provide better service to customers. The technology used to develop the system is now outdated, largely because standard techniques used today that allow changes to be made quickly were not available when the system was developed. Altering the current system to support changing SEMCO Gas's customer service requirements has become difficult.

Q. Describe examples of the problems encountered with the current CIS.

A. The Company has introduced numerous new technology systems during the past few years. All of these major systems need to interface and exchange data with the CIS. SEMCO Gas's automated meter reading system is an example. In making the changeover to the automated meter reading system, it took substantial effort to ensure that automated meter readings could be transmitted to, and understood and processed by, the current CIS. The reason for that interface issue is simple: the underlying structure of the current CIS was designed using Report Program Generator ("RPG") programming language, a popular programming language at the time of design. RPG did not support relational database design, so the current CIS is designed in a flat-file format. It was never intended to be what is termed an "open architected" system, supporting the sharing of data among numerous systems. (In contrast, the new CIS uses an Oracle database structure that is arguably the most open architected system available today.) Viewed in more general terms, this problem of making sure that other critical systems are linked appropriately with the current CIS means that SEMCO Gas cannot effectively offer improvements to customers, such as bill presentment options, budget billing programs, and handling of customer inquiries or easily adapt to tariff changes, such as the implementation of the emergency billing rules required last year.

In addition, the current CIS does not provide management reporting required for analyzing customer data to make improvements. Because the system does not use an open, table-driven structure, standard report

writing tools, such as COGNOS Report Writer and Crystal Report Writer, cannot be used to access information in the system. All reports must be created by an application programmer as a "custom" request. (With the new CIS, users of the system will be able to take advantage of standard report writing tools, to get the information from the system more easily).

Q. What has been done to date in an effort to replace the current CIS with a new system?

A. SEMCO Gas initiated a project to identify requirements for a new system that would provide the Company with the flexibility and configurability needed to improve its customer-related processes and to implement changes more quickly. Requirements for a new system were identified and sent to potential vendors. Responses from potential vendors were reviewed, to ensure that their proposals satisfied the Company's needs. After this evaluation, the Company selected three potential vendors, each of which demonstrated their products and related capabilities to the team assigned to this project. From those three, SEMCO Gas selected one vendor with which to negotiate an agreement for a new system. A contract was signed with this vendor in December 2004.

Since execution of the contract, a project manager for implementation has been identified, project teams with individuals from SEMCO Gas and the vendor have been established, the necessary hardware and third-party software has been ordered and installed, and a detailed implementation plan has been created. I describe the implementation phase for the project later in my testimony.

Q. What is the anticipated cost of the new CIS?

A. SEMCO Gas has a fixed price contract with its CIS vendor. The price is based on a statement of work created to support SEMCO's requirements at contract signing. Changes to the statement of work to support new requirements, such as the implementation of new billing rules, would require additional payments to the vendor for modifications. This is discussed at greater length in Mr. Forsyth's testimony.

The total amount to be paid to the CIS vendor for the new system and implementation services in the years 2005 and 2006 is $4,106,688. Based on current customer data, the portion of the $4,106,688 to be allocated to the Company's MPSC Division customers, on the proportion of total Michigan customers is $3,572,818.

In 2005, the total CIS implementation costs were $1,799,350. These costs consisted of $1,253,167, which was paid to the CIS vendor for its product licenses, hardware costs, and implementation services. The rest of the costs were for third-party software, capitalized interest associated with the CIS project, and third-party implementation support services. The portion of the total costs incurred in 2005 allocated to the Company's MPSC Division was $1,565,435.

The costs for 2006 are anticipated to be $4,340,812 in total, with $3,776,507 being allocated to the Company's MPSC Division. The total for 2006 includes $2,853,521 for product licenses, hardware costs, and implementation services from the CIS vendor. Other costs in 2006 include

capitalized interest associated with the CIS project and license and services from third-party vendors for support of the CIS implementation.

The detailed costs associated with the CIS implementation project for the period 2005 through 2008 are presented in Exhibit A-12, Schedule 2.

Q. What is the expected useful life of the new system?

A. The useful life of the new system, for purposes of recovery of the cost of the system from a ratemaking perspective, is from five to seven years. This is typical of modern computer-based systems, since computer technology changes so rapidly, with advances in hardware and software system components.

Q. Does that mean that the new CIS will not be in service beyond that point in time?

A. No, though it is possible that technology will change so rapidly and significantly that it would make sense to replace the new CIS in that timeframe to reap the benefits of the change in technology, what is more likely, in my view, is that the Company will be faced with making substantial additional capital investments as the new CIS ages, to maintain and upgrade system functionality. To me, it makes sense to take these facts – the possibility of rapid and substantial technological change and the likelihood of future substantial capital investments – into account in determining how to allow the Company to recover the initial costs of the new CIS, by permitting the Company to recover those costs over the timeframe I have described.

Q. What has been accomplished to date with the implementation of the new CIS, and when will the new system be fully implemented?

A. The project implementation phase was started in early-2005. Detailed business process analysis documents were created for every process to be supported by the new CIS. Detailed scope documents for all identified system interfaces and modifications were created and approved by the Company employees who are responsible for the systems that link in some fashion with the new CIS. A reporting requirements matrix and an employee training requirements matrix were created, again after much analysis by the vendor and the responsible Company employees. Data conversion planning and testing has been an on-going activity. The business process analysis documents have been used to perform initial system setup and configuration to meet SEMCO Gas's requirements. Additional activities to be completed are the development and use of testing scripts, the performance of a mock "go live" test of the new CIS, the development of required reports, and the final data migration and system changeover. The current project plan is for implementation to be completed in time to put the new CIS into service at the beginning of the fourth quarter of 2006.

<u>Field Order System</u>

Q. What is the purpose of the field order system?

A. The field order system ("FOS"") supports all of the major business processes having to do with the creation, scheduling, and reporting of work orders, which are the means by which requests for work to be done

are translated into work actually completed in the field. The FOS is used to process work order information generated by the CIS, which includes assigning work appropriately to SEMCO Gas employees based on the order type, requested time of performance, and employee skills and knowledge. The FOS also exchanges work order status information with the CIS, so such status information is available for use in responding to customer inquiries. The FOS also makes facility mapping information available to SEMCO Gas employees performing work in the field and tracks information for time and payroll reporting.

Q. Why is a new FOS application necessary?

A. SEMCO Gas's current FOS is no longer "supported" by the vendor, which means that there is no application support to help solve system problems as they arise. The current system has not been upgraded since its original implementation in 1997. In addition, the hardware that supports the current FOS application in the field is no longer available. Simply put, after nearly a decade, the current system is outdated.

Also, with the implementation of a new CIS application, the Company would have been obliged to incur substantial costs (on the order of $500,000 or more) to make sure that this outdated system was properly linked to the new CIS. (As noted above, the CIS is a source of work orders, and the FOS communicates the status of work orders back to the CIS, so that customer inquiries can be answered.)

The new FOS application addresses all of these software, hardware, support, and interface issues.

Q. What has been done to date in an effort to replace the current FOS?

A. SEMCO Gas initiated a project to identify requirements for a new system that would replace the current FOS in December 2004. Requirements for a new system were identified and sent to potential vendors. Responses from potential vendors were reviewed, to ensure that their proposals satisfied the Company's needs. After this evaluation, the Company selected two potential vendors. Those vendors demonstrated their products and other capabilities to the team assigned to this project. From those two, SEMCO Gas selected one vendor with which to negotiate an agreement for a new FOS. A contract was signed with this vendor in June 2005.

Q. When is the new system expected to be completed and operational?

A. The project completion date for phase I of the implementation is expected to be the beginning of the fourth quarter of 2006. Phase I will include the implementation activities required to ensure that the FOS is linked properly with the new CIS application. These activities include the receipt of work order information from the CIS system, the ability for Company service employees to complete order information in real time, the automatic "intelligent" scheduling of work to service employees, and the retrieval of critical infrastructure maps from SEMCO Gas's mapping system for use by Company field personnel. These activities will be available after Phase I in the areas where SEMCO Gas currently has FOS technology.

Phase II of the project will continue into 2007 and 2008. Phase II will provide the capabilities previously described to field personnel in all of SEMCO Gas's Michigan service territories, and enable additional work order types to be presented to all field personnel.

Q. What are the anticipated costs of the new system?

A. SEMCO Gas has a fixed price contract with its FOS vendor. The total amount to be paid to the FOS vendor for the new system and implementation services is $2,440,248. The portion of the total FOS vendor costs to be allocated to the Company's MPSC Division customers, on the proportion of total Michigan customers, is $2,123,016.

In 2005, the total FOS implementation costs were $314,314. These costs consisted of $273,782 which was paid to the FOS vendor for their product licenses and implementation services. The rest of the costs were for capitalized interest associated with the FOS project and third-party implementation support services. The portion of the total costs incurred in 2005 allocated to the Company's MPSC Division was $273,453.

The costs for 2006 are anticipated to be $1,402,771 in total, with $1,220,411 being allocated to the Company's MPSC Division. The total for 2006 includes $944,425 for product licenses, hardware costs, and implementation services from the FOS vendor. Other costs in 2006 include capitalized interest associated with the FOS project and licenses and services from third-party vendors for support of the FOS implementation.

In the years 2007 and 2008, the Company anticipates spending $2,502,171 for Phase II of the FOS implementation. Of this amount, $2,176,889 will be allocated to the Company's MPSC Division.

The detailed costs associated with the FOS implementation project for the period 2005 through 2008 are presented in Exhibit A-12, Schedule 3.

Q. What is the expected useful life of the new system?

A. The useful life of the new system, for purposes of recovery of the cost of the system from a ratemaking perspective, is from five to seven years. As noted in my discussion of the new CIS, this is typical of modern computer-based systems, since computer technology changes so rapidly, with advances in hardware and software system components.

Q. Does that mean that the new FOS will not be in service beyond that point in time?

A. No, though again, as I noted in discussing the new CIS, it is possible that technology will change so rapidly and significantly that it would make sense to replace the new FOS in that timeframe, to reap the benefits of the change in technology. As stated earlier, what is more likely, in my view, is that the Company will be faced with making substantial additional capital investments as the new FOS ages, to maintain and upgrade system functionality. Again, to me, it makes sense to take these facts – the possibility of rapid and substantial technological change and the likelihood of future substantial capital investments – into account in determining how best to allow the Company to recover the initial costs of

the new FOS, by permitting the Company to recover those costs over the timeframe I have described.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF RICK L. AYERS

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony Of Rick L. Ayers
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is Rick Ayers, and my business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

Q. By whom are you employed and what is your position with that employer?

A. My title is Director of Information Technology for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company").

Q. Please describe your academic background and business experience.

A. In 1993, I graduated from Walsh College of Accountancy and Business Administration, Troy, Michigan, with a Bachelor's degree in Business Administration. In my current position, I oversee information technology projects and planning activities for the Company. I have held positions of increasing responsibility at SEMCO Gas since 1989, including positions in Information Technology, Training and Development, Customer Service and Planning. I held Director level positions in Customer Service and Planning for SEMCO Gas before moving to my current position. Prior to working for SEMCO Gas, I was employed by North American Benefit Association as an application programmer.

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

A. My testimony describes two new technology applications to be used to provide service to customers, explains why SEMCO Gas needs the new applications, and details the costs associated with the new applications.

Q. Have these new technology applications been approved by SEMCO Gas's Board of Directors?

A. Yes, the funding for these new technology applications has been approved by SEMCO Gas's Board of Directors.

Q. Does SEMCO Gas anticipate cost savings from the implementation of the new technology applications?

A. SEMCO Gas does not anticipate cost savings from the implementation of the new technology applications, through the time period reflected in this case, due to the costs associated with implementing and maintaining new technologies required by the applications, the costs associated with implementing new business processes, and the costs associated with training employees during this time period.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits, which were prepared by me or under my direct supervision:

Exhibit A-12, Schedule 2, CIS System Implementation

Exhibit A-12, Schedule 3, FOS System Implementation

Q. Have you previously testified before the Michigan Public Service Commission?

A. Yes, I provided testimony on technology systems in MPSC Case Number U-14338.

<u>Customer Information System</u>

Q. What is the purpose of the Company's customer information system?

A. The Company's customer information system ("CIS") is a computerized system for handling all aspects of the Company-customer relationship. This includes (i) tracking basic customer account information (such as a

customer's name, service and billing addresses, account number, and rate classification), (ii) providing information from this computerized database to Customer Service Representatives, so that they can answer customer inquiries, (iii) creating work orders that cause Company personnel to provide various services for customers (such as installing new gas service lines or checking on suspected gas leaks), (iv) tracking customer gas consumption, (v) billing customers for their gas consumption and other services, and (vi) processing customer payments and providing the revenue data needed for the Company's books and records.

Q. Why is a new application necessary?

A. The Company's current CIS was originally installed over 25 years ago. That system was developed by SEMCO Gas itself to support customer service requirements at that time. Because this was the available technology at the time, the old CIS system was "hard coded" and therefore it is not a flexible, configurable system. Over the intervening years, the system has been modified from time-to-time, to reflect and support changes in processes that were either required by tariff or needed to provide better service to customers. The technology used to develop the system is now outdated, largely because standard techniques used today that allow changes to be made quickly were not available when the system was developed. Altering the current system to support changing SEMCO Gas's customer service requirements has become difficult.

Q. Describe examples of the problems encountered with the current CIS.

A. The Company has introduced numerous new technology systems during the past few years. All of these major systems need to interface and exchange data with the CIS. SEMCO Gas's automated meter reading system is an example. In making the changeover to the automated meter reading system, it took substantial effort to ensure that automated meter readings could be transmitted to, and understood and processed by, the current CIS. The reason for that interface issue is simple: the underlying structure of the current CIS was designed using Report Program Generator ("RPG") programming language, a popular programming language at the time of design. RPG did not support relational database design, so the current CIS is designed in a flat-file format. It was never intended to be what is termed an "open architected" system, supporting the sharing of data among numerous systems. (In contrast, the new CIS uses an Oracle database structure that is arguably the most open architected system available today.) Viewed in more general terms, this problem of making sure that other critical systems are linked appropriately with the current CIS means that SEMCO Gas cannot effectively offer improvements to customers, such as bill presentment options, budget billing programs, and handling of customer inquiries or easily adapt to tariff changes, such as the implementation of the emergency billing rules required last year.

In addition, the current CIS does not provide management reporting required for analyzing customer data to make improvements. Because the system does not use an open, table-driven structure, standard report

writing tools, such as COGNOS Report Writer and Crystal Report Writer, cannot be used to access information in the system. All reports must be created by an application programmer as a "custom" request. (With the new CIS, users of the system will be able to take advantage of standard report writing tools, to get the information from the system more easily).

Q. What has been done to date in an effort to replace the current CIS with a new system?

A. SEMCO Gas initiated a project to identify requirements for a new system that would provide the Company with the flexibility and configurability needed to improve its customer-related processes and to implement changes more quickly. Requirements for a new system were identified and sent to potential vendors. Responses from potential vendors were reviewed, to ensure that their proposals satisfied the Company's needs. After this evaluation, the Company selected three potential vendors, each of which demonstrated their products and related capabilities to the team assigned to this project. From those three, SEMCO Gas selected one vendor with which to negotiate an agreement for a new system. A contract was signed with this vendor in December 2004.

Since execution of the contract, a project manager for implementation has been identified, project teams with individuals from SEMCO Gas and the vendor have been established, the necessary hardware and third-party software has been ordered and installed, and a detailed implementation plan has been created. I describe the implementation phase for the project later in my testimony.

Q. What is the anticipated cost of the new CIS?

A. SEMCO Gas has a fixed price contract with its CIS vendor. The price is based on a statement of work created to support SEMCO's requirements at contract signing. Changes to the statement of work to support new requirements, such as the implementation of new billing rules, would require additional payments to the vendor for modifications. This is discussed at greater length in Mr. Forsyth's testimony.

The total amount to be paid to the CIS vendor for the new system and implementation services in the years 2005 and 2006 is $4,106,688. Based on current customer data, the portion of the $4,106,688 to be allocated to the Company's MPSC Division customers, on the proportion of total Michigan customers is $3,572,818.

In 2005, the total CIS implementation costs were $1,799,350. These costs consisted of $1,253,167, which was paid to the CIS vendor for its product licenses, hardware costs, and implementation services. The rest of the costs were for third-party software, capitalized interest associated with the CIS project, and third-party implementation support services. The portion of the total costs incurred in 2005 allocated to the Company's MPSC Division was $1,565,435.

The costs for 2006 are anticipated to be $4,340,812 in total, with $3,776,507 being allocated to the Company's MPSC Division. The total for 2006 includes $2,853,521 for product licenses, hardware costs, and implementation services from the CIS vendor. Other costs in 2006 include

capitalized interest associated with the CIS project and license and services from third-party vendors for support of the CIS implementation.

The detailed costs associated with the CIS implementation project for the period 2005 through 2008 are presented in Exhibit A-12, Schedule 2.

Q. What is the expected useful life of the new system?

A. The useful life of the new system, for purposes of recovery of the cost of the system from a ratemaking perspective, is from five to seven years. This is typical of modern computer-based systems, since computer technology changes so rapidly, with advances in hardware and software system components.

Q. Does that mean that the new CIS will not be in service beyond that point in time?

A. No, though it is possible that technology will change so rapidly and significantly that it would make sense to replace the new CIS in that timeframe to reap the benefits of the change in technology, what is more likely, in my view, is that the Company will be faced with making substantial additional capital investments as the new CIS ages, to maintain and upgrade system functionality. To me, it makes sense to take these facts – the possibility of rapid and substantial technological change and the likelihood of future substantial capital investments – into account in determining how to allow the Company to recover the initial costs of the new CIS, by permitting the Company to recover those costs over the timeframe I have described.

Q. What has been accomplished to date with the implementation of the new CIS, and when will the new system be fully implemented?

A. The project implementation phase was started in early-2005. Detailed business process analysis documents were created for every process to be supported by the new CIS. Detailed scope documents for all identified system interfaces and modifications were created and approved by the Company employees who are responsible for the systems that link in some fashion with the new CIS. A reporting requirements matrix and an employee training requirements matrix were created, again after much analysis by the vendor and the responsible Company employees. Data conversion planning and testing has been an on-going activity. The business process analysis documents have been used to perform initial system setup and configuration to meet SEMCO Gas's requirements. Additional activities to be completed are the development and use of testing scripts, the performance of a mock "go live" test of the new CIS, the development of required reports, and the final data migration and system changeover. The current project plan is for implementation to be completed in time to put the new CIS into service at the beginning of the fourth quarter of 2006.

<u>Field Order System</u>

Q. What is the purpose of the field order system?

A. The field order system ("FOS"") supports all of the major business processes having to do with the creation, scheduling, and reporting of work orders, which are the means by which requests for work to be done

are translated into work actually completed in the field. The FOS is used to process work order information generated by the CIS, which includes assigning work appropriately to SEMCO Gas employees based on the order type, requested time of performance, and employee skills and knowledge. The FOS also exchanges work order status information with the CIS, so such status information is available for use in responding to customer inquiries. The FOS also makes facility mapping information available to SEMCO Gas employees performing work in the field and tracks information for time and payroll reporting.

Q. Why is a new FOS application necessary?

A. SEMCO Gas's current FOS is no longer "supported" by the vendor, which means that there is no application support to help solve system problems as they arise. The current system has not been upgraded since its original implementation in 1997. In addition, the hardware that supports the current FOS application in the field is no longer available. Simply put, after nearly a decade, the current system is outdated.

Also, with the implementation of a new CIS application, the Company would have been obliged to incur substantial costs (on the order of $500,000 or more) to make sure that this outdated system was properly linked to the new CIS. (As noted above, the CIS is a source of work orders, and the FOS communicates the status of work orders back to the CIS, so that customer inquiries can be answered.)

The new FOS application addresses all of these software, hardware, support, and interface issues.

Q. What has been done to date in an effort to replace the current FOS?

A. SEMCO Gas initiated a project to identify requirements for a new system that would replace the current FOS in December 2004. Requirements for a new system were identified and sent to potential vendors. Responses from potential vendors were reviewed, to ensure that their proposals satisfied the Company's needs. After this evaluation, the Company selected two potential vendors. Those vendors demonstrated their products and other capabilities to the team assigned to this project. From those two, SEMCO Gas selected one vendor with which to negotiate an agreement for a new FOS. A contract was signed with this vendor in June 2005.

Q. When is the new system expected to be completed and operational?

A. The project completion date for phase I of the implementation is expected to be the beginning of the fourth quarter of 2006. Phase I will include the implementation activities required to ensure that the FOS is linked properly with the new CIS application. These activities include the receipt of work order information from the CIS system, the ability for Company service employees to complete order information in real time, the automatic "intelligent" scheduling of work to service employees, and the retrieval of critical infrastructure maps from SEMCO Gas's mapping system for use by Company field personnel. These activities will be available after Phase I in the areas where SEMCO Gas currently has FOS technology.

Phase II of the project will continue into 2007 and 2008. Phase II will provide the capabilities previously described to field personnel in all of SEMCO Gas's Michigan service territories, and enable additional work order types to be presented to all field personnel.

Q. What are the anticipated costs of the new system?

A. SEMCO Gas has a fixed price contract with its FOS vendor. The total amount to be paid to the FOS vendor for the new system and implementation services is $2,440,248. The portion of the total FOS vendor costs to be allocated to the Company's MPSC Division customers, on the proportion of total Michigan customers, is $2,123,016.

In 2005, the total FOS implementation costs were $314,314. These costs consisted of $273,782 which was paid to the FOS vendor for their product licenses and implementation services. The rest of the costs were for capitalized interest associated with the FOS project and third-party implementation support services. The portion of the total costs incurred in 2005 allocated to the Company's MPSC Division was $273,453.

The costs for 2006 are anticipated to be $1,402,771 in total, with $1,220,411 being allocated to the Company's MPSC Division. The total for 2006 includes $944,425 for product licenses, hardware costs, and implementation services from the FOS vendor. Other costs in 2006 include capitalized interest associated with the FOS project and licenses and services from third-party vendors for support of the FOS implementation.

In the years 2007 and 2008, the Company anticipates spending $2,502,171 for Phase II of the FOS implementation. Of this amount, $2,176,889 will be allocated to the Company's MPSC Division.

The detailed costs associated with the FOS implementation project for the period 2005 through 2008 are presented in Exhibit A-12, Schedule 3.

Q. What is the expected useful life of the new system?

A. The useful life of the new system, for purposes of recovery of the cost of the system from a ratemaking perspective, is from five to seven years. As noted in my discussion of the new CIS, this is typical of modern computer-based systems, since computer technology changes so rapidly, with advances in hardware and software system components.

Q. Does that mean that the new FOS will not be in service beyond that point in time?

A. No, though again, as I noted in discussing the new CIS, it is possible that technology will change so rapidly and significantly that it would make sense to replace the new FOS in that timeframe, to reap the benefits of the change in technology. As stated earlier, what is more likely, in my view, is that the Company will be faced with making substantial additional capital investments as the new FOS ages, to maintain and upgrade system functionality. Again, to me, it makes sense to take these facts – the possibility of rapid and substantial technological change and the likelihood of future substantial capital investments – into account in determining how best to allow the Company to recover the initial costs of

the new FOS, by permitting the Company to recover those costs over the timeframe I have described.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **SEMCO ENERGY GAS COMPANY** for authority to redesign and increase its rates for the sale and transportation of natural gas in its MPSC Division and for other relief.	)))))))	Case No. U-14893

DIRECT TESTIMONY AND EXHIBITS OF STEVEN W. WARSINSKE

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Steven W. Warsinske
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is Steven W. Warsinske. My business address is 1411 Third Street, Suite A, Port Huron, MI 48060.

Q. By whom are you employed and what is your position with that employer?

A. I am the Vice President and Controller of SEMCO Energy, Inc. ("SEMCO") and I am appearing in this proceeding on behalf of SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"). SEMCO Gas is a division of SEMCO Energy, Inc.

Q. What are your responsibilities?

A. As Vice President and Controller, I am responsible for the preparation and control of all accounting records and systems of SEMCO, including financial statements and reports. I am also responsible for income tax compliance and accounting, and regulatory reporting. I am responsible for developing accounting methods and procedures. These methods and procedures are designed to provide internal accounting controls. I am responsible for ensuring that the Company conducts its business in accordance with accounting standards prescribed by the Michigan Public Service Commission ("Commission" or "MPSC") in the Uniform System of Accounts. My ongoing responsibility for SEMCO's accounting also involves consideration of MPSC, Securities and Exchange Commission and Financial Accounting Standards Board ("FASB") accounting proposals and pronouncements.

Q. Please summarize your academic background.

A. I graduated from Eastern Michigan University in 1977 with a BBA in Accounting. I also hold a Master's of Science Degree in Taxation from Walsh College.

Q. Please summarize your employment and professional experience.

A. I have been employed by SEMCO since 1978. Prior to my current position, I held various positions in the finance and accounting area with SEMCO.

Q. Have you previously testified before this Commission?

A. Yes. I have provided testimony in SEMCO Gas's 2002 general rate case, MPSC Case No. U-13575, and in SEMCO Gas's 2004 general rate case, MPSC Case No. U-14338. I most recently provided testimony in MPSC Case No. U-14292, which involved the establishment of appropriate accounting and ratemaking treatment for property retirements and related salvage under Statement of Financial Accounting Standards ("SFAS") No. 143.

Q. What is the purpose of your testimony?

A. I am presenting testimony and exhibits that develop parts of the Company's revenue deficiency for the 2005 historic year through the 2007 test year.

Q. Please identify the exhibits that you are sponsoring in this proceeding.

A. I am sponsoring the following exhibits:

Exhibit A-5, Schedule E-1	Corporate Structure of the Affiliated Group
Exhibit A-5, Schedule E-2	Summary of Costs Billed To and From Affiliated Companies
Exhibit A-5, Schedule E-3	Affiliated Companies Rate of Return on Common Equity – 2005
Exhibit A-5, Schedule E-4	Consolidating Balance Sheets – 2005
Exhibit A-5, Schedule E-5	Consolidating Income Statement – 2005
Exhibit A-9, Schedule C-9	Employee Pension and Retiree Medical Expense
Exhibit A-9, Schedule C-8	Medical and Dental Programs Expense
Exhibit A-9, Schedule C-7	Long-Term Incentive Program Expense
Exhibit A-9, Schedule C-14	Accounting For Lost and Unaccounted For Gas Costs
Exhibit A-9, Schedule C-18	Peninsular Gas Company O&M Expense Adjustment

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

A. Yes they were.

AFFILIATED COMPANY TRANSACTIONS

Q. Which of your exhibits address affiliated company transactions?

A. I am sponsoring Exhibit A-5, Schedules E-1 through E-5. These schedules have been prepared to satisfy the MPSC's filing requirements for gas utility rate cases as provided in MPSC Case No. U-10039.

Q. What is the purpose of these exhibits?

A. Exhibit A-5, Schedule E-1 shows the interrelationship of all members of the corporate group, whether or not the members are involved in regulated activities. Exhibit A-5, Schedule E-2 is a summary of costs billed to and from affiliated companies and included in the historical test year results. Exhibit A-5, Schedule E-3 is a report of the affiliated companies' rate of return on common equity. Exhibit A-5, Schedule E-4 is a consolidating balance sheet for SEMCO as of December 31, 2005. Exhibit A-5, Schedule E-5 is a consolidating income statement for SEMCO as of December 31, 2005.

Q. Please explain further Exhibit A-5, Schedule E-1, Corporate Structure of the Affiliated Group.

A. This exhibit is an organization chart which shows all of SEMCO Energy, Inc. divisions and subsidiaries.

Q. Are SEMCO Gas and ENSTAR Natural Gas Company subsidiaries of SEMCO?

A. No, they are not. They are divisions of SEMCO that are treated as stand-alone entities for accounting and for affiliated transaction purposes. SEMCO Gas is made up of two separate entities - Battle Creek Gas Company, or the Battle Creek Division, and what is termed the "MPSC Division," which is also referred to as SEMCO Gas in this filing. These two entities are also treated as stand-alone entities for accounting and for affiliated transaction purposes.

Q. Please explain the significance of there being affiliations among various SEMCO entities.

A. As I understand the Commission's rules on this subject, all entities, owned in full or in part, by SEMCO, or by subsidiaries of SEMCO, and SEMCO divisions are considered "Affiliates" or "Affiliated Companies." Affiliates engaged in the business of the local distribution of natural gas, as a gas utility, are called "Utility Affiliates." All other Affiliates not directly engaged in the local distribution of natural gas are called "Non-Utility Affiliates." All transactions between and among Affiliates are governed by policies contained in SEMCO's "Affiliated Transactions Policy Manual." Included in this manual are policies that govern the billing for services provided by or for SEMCO Gas.

Q. Please explain further Exhibit A-5, Schedule E-2, Summary of Costs Billed To and From Affiliated Companies.

A. This schedule shows the costs billed to and from Affiliated Companies, how the costs are classified, and how they are priced.

Q. Please describe the types of services performed by SEMCO Gas for Affiliated Companies.

A. SEMCO Gas employees also perform work for both SEMCO and the Battle Creek Division. This consists of both administrative work (such as payroll, accounts payable, property accounting, call center and other customer related services) and field work (such as leak repairs, drafting and other engineering services). Field work would typically be performed for the Battle Creek Division as opposed to SEMCO.

Q. Please describe the types of services performed for the Company by Affiliated Companies.

A. There are three main categories of these services. The first is the allocation of SEMCO indirect costs. Examples of these types of costs would be investor relations, risk management and corporate accounting.

Q. How are those indirect costs allocated?

A. They are allocated through the use of the "Massachusetts Formula," which has been used by the Company and other Michigan utilities, as a way to allocate common costs.

Q. What other charges are billed to the Company by Affiliated Companies?

A. The other two categories consist of work done by Battle Creek Division employees and work done by SEMCO Information Technology Company (information technology, computer programming and data processing services).

Q. How are the costs to and from Affiliated Companies priced?

A. All of the direct activity is priced at actual cost with applicable overheads. This would primarily consist of labor costs incurred, along with allocated overheads and employee benefits. The indirect allocations are at direct cost. The information technology work is at a contract price, which falls within SEMCO's affiliated transactions guidelines which states, "these services shall be billed at the lesser of fair market value or 10% over fully allocated costs."

BENEFIT PLANS

Q. Please discuss Exhibit A-9, Schedule C-9, Employee Pension and Retiree Medical Expense.

A. This schedule shows the historical cost for 2005 of the Company's pension and retiree medical expense. It also shows the estimated 2006 costs for those same items.

Q. What is included in the actual 2005 numbers?

A. The pension expense amount is the historical 2005 expense, as determined under SFAS 87 "Employers' Accounting for Pensions" ("SFAS 87"). The retiree medical expense is determined under SFAS 106 "Employers' Accounting for Post Retirement Benefits Other Than Pensions" ("SFAS 106"). These amounts are provided by the Company's actuaries, Watson Wyatt and Company. The retiree medical expense is broken down into two components. The first component is the current year retiree medical expense. The second component is an amortization of previously deferred retiree medical costs. Prior to getting regulatory approval for the recovery of retiree medical benefit costs in rates, the Company deferred, as a regulatory asset, the portion of retiree medical

expenses that were not yet provided for in customer rates. After receiving regulatory approval for recovery of such costs, the Company began amortizing, as retiree medical expense, the amounts previously deferred.

Q. What are the components of annual pension and retiree medical expense?

A. There are four components of this expense:

Service Cost

The plan's service cost represents the value of the benefits earned during the year. This is determined individually for each participant, based on his or her specific employee demographics.

Interest Cost

Interest cost represents interest on the plan's liabilities. All future benefits are discounted back to the valuation date based on a discount rate assumption. This assumption is made each year by the plan's actuary, following requirements set forth by SFAS 87 and SFAS 106, and the assumption is reviewed by the Company's external auditors.

Expected Earnings and Plan Assets

The expected earnings on plan assets each year is a reduction in annual expense. The expected earnings assumption is reviewed periodically by the plan's actuary, following SFAS 87 guidance, and is intended to be a long-term assumption based on an estimate of the expected long-term investment earnings of the plan assets.

Amortization of Gains or Losses, Prior Service Costs, and any Transitional Amounts

This component represents amortizations of various actual plan experiences that are not anticipated by the plan's actuarial assumptions. For example, plan experience gains or losses and any plan design changes would be amortized and included as a part of this component of plan expense. The amortizations can be either positive or negative.

Q. What are the reasons for the increase in pension expense between 2005 and 2006 ?

A. About 50% of the increase is due to a change in the plan discount rate. The discount rate is the interest rate that is used to determine present values for future benefit obligations. This rate must be determined at the measurement date each year and is based on yields available on high quality, fixed income investments. The discount rate used must be approved by the Company's external auditors. The discount rate assumption decreased from 5.75% in 2005 to 5.50% in 2006, basically based on market data.

The balance of the increase is due to a number of factors. They include investment losses for 2005, due to the fact that the plan assets returned less than the overall expected return. In addition, the expense increased to reflect phasing in a component of investment losses that occurred during the four years prior to 2005. The Company employs a smoothing method for determining the market value of assets for its pension expense, as do many other employers, to help reduce the volatility in annual expense. The estimated increase in Pension Benefit Guaranty Corporation premiums, due to expected changes in the law, are paid out of the trust, and these premiums also increase the Company's overall pension expense. These items are partially offset by an increase in the expected return on plan assets, due to additional cash contributions of $2.8 million made in 2005. An increase in the expected return on assets reduces the overall expense.

Q. What are the reasons for the increase in retiree medical expense between 2005 and 2006?

A. About 70% of the increase is that retiree health care inflation rates were increased for 2006 to better reflect anticipated future cost increase trends in retiree medical and prescription drug benefits. Over the last few years, the Company has instituted various cost-cutting measures and increased retiree contributions affecting this benefit. The Company also has

qualified for the retiree drug subsidy under the Medicare Modernization Act of 2003 for plan years beginning on and after January 1, 2006. Despite those changes, the overall cost of health care in the United States has risen dramatically, which has necessitated changes in assumptions about this expense item.

Other items which have caused an increase in this expense are the lowering of the discount rate from 5.75% to 5.50% and the effect of market returns that are less than the assumed returns for plan assets. These items are partially offset by the fact that the Company has been paying for actual retiree medical costs out of corporate assets. For 2005, those payments were significantly higher than the actual 2005 service expense.

Q. Please discuss Exhibit A-9, Schedule C-8, Medical and Dental Programs Expense.

A. This schedule shows the historical 2005 costs for medical and dental expenses. It also shows the estimated 2006 and 2007 amounts for these items.

Q. How did SEMCO develop this data?

A. SEMCO relies on McGraw Wentworth in Troy, Michigan as its advisor on health and welfare benefits. McGraw Wentworth works primarily with mid-sized employers, such as SEMCO, and the firm has 135 clients with an average of approximately 550 employees each.

To determine the expected medical cost trends for 2006 and 2007, McGraw Wentworth reviewed SEMCO's recent health care cost history and conducted a market survey of large national and local carriers to see what their actuaries are expecting in health care cost increases. In addition, nationally recognized surveys were reviewed to confirm the market survey data and develop accurate expense estimates for SEMCO.

Q. Why do medical costs increase so much compared to the general rate of inflation?

A. As I understand the data the following factors contribute to this increase above the general rate of inflation:

- New treatments are developed each year, expanding the services typically covered by group health plans.
- An aging population continues to require more care. Given its low employee turnover, this manifests itself in an aging workforce at SEMCO, and that aging workforce is similar to the general population in requiring more care.
- Direct to consumer drug advertising has increased both the cost of prescription drugs and consumer demand for those drugs.
- Expanded therapeutic indications promote earlier or expanded treatment for certain conditions (e.g., AMA guidelines were lowered for the recommended cholesterol levels where a patient should be treated, significantly expanding the number of medical plan participants who meet the criteria for being monitored and treated for high cholesterol).
- The overall health status of the population continues to deteriorate, with obesity and smoking continuing to escalate the numbers of individuals with chronic conditions.
- Consumer rejection of managed care constraints has limited the ability of medical coverage providers to manage health care providers in the way in which those providers treat patients.
- The declining value of fixed dollar co-pays and deductibles typically result in an employer's paying a majority of the increase in medical plan costs each year.

Q. Has SEMCO made changes in medical, dental and prescription coverage to address these escalating costs?

A. Yes. SEMCO has made changes in these coverages, where possible, to address these escalating costs. Employees currently pay approximately 17% of the premium associated with these coverages, and co-pays and deductibles have been increased. Nonetheless, despite these plan

design changes to position SEMCO's benefits at the middle of the market, SEMCO expects to experience the increase in this expense described in my testimony.

INCENTIVE COMPENSATION

Q. Please discuss Exhibit A-9, Schedule C-7, Long-Term Incentive Program Expense.

A. There are three components of SEMCO's long-term incentive plan: stock options; restricted stock units; and employee performance share units.

Q. Why isn't there any 2005 expense for stock options on the schedule?

A. Prior to 2006, the Company accounted for stock options using what is called the "intrinsic value method" provided for under the provisions and related interpretations of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"). In accordance with SFAS 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), the Company had chosen to account for these transactions under APB 25 for purposes of determining net income but had to present the pro forma disclosures required by SFAS 123 as amended by SFAS 148, "Accounting for Stock-Based Compensation – Transition and Disclosure," in its periodic public filings. Under the intrinsic value method, there was no compensation expense associated with stock options, and therefore there was no expense recorded on SEMCO's books and records in 2005.

In December 2004, the FASB issued SFAS 123-R (Revised 2004) – "Share-Based Payment." This standard supersedes APB No. 25 and requires recognition of expense in the financial statements of the cost of stock options based on the fair value of the award at the grant date.

As a result, the Company started expensing stock options in its financial statements on and after January 1, 2006. The fair value of the options was estimated at the date of grant using a Black-Scholes option pricing model. This schedule shows the estimated stock options expense for

2006 and 2007, with the portion allocated to SEMCO Gas through the Massachusetts formula.

Q. What are the differences between the 2006 and 2007 expense for this item?

A. Each stock option grant has a three-year vesting period. The expense associated with each option grant is expensed over the three-year vesting period. Once an option grant is fully vested, there is no additional expense to accrue, because, at this point, the option has been earned by the employee as part of his or her compensation. The 2007 expense is based on the continued vesting of previously-issued stock options and the granting of additional options in 2007.

Q. Please describe the restricted stock unit expense and employee performance share unit expense shown on the schedule.

A. Prior to January 1, 2006, these kinds of grants were expensed under APB 25. APB 25 required performance share units to be expensed under variable accounting (mark-to-market) and restricted stock units, with time-lapse vesting, under fixed accounting (fair value expense at the date of the grant). Starting in 2006, with the change in accounting rules I described earlier, SEMCO calculates the expense for both kinds of grants by multiplying the units granted by the fair market value of SEMCO's common stock on the date of the grant (as determined under SFAS 123-R) and expenses the units over their applicable vesting period. The restricted stock units were granted to certain executives. One of the restricted stock unit grants in 2005 has a three-year service requirement, with what is known as cliff vesting at the end of that period. The remainder of the restricted stock unit grants have a combination of service and performance requirements and vest in blocks from their grant dates to March 31, 2007, if the service and performance requirements are met. The performance share units were granted to certain management level employees. They have a three-year term, with cliff vesting. The employees will vest in these performance share units only on the

achievement of certain performance criteria, which are established at the grant date.

Q. How was the 2007 expense for these kinds of grants determined?

A. The 2007 expense for these grants was based on the continued vesting of the existing units and the granting of additional units in 2007, at the same dollar amount as the 2006 grants.

Q. Why did SEMCO award stock options, restricted stock units, and performance share units to employees as part of their compensation?

A. Like any employer, SEMCO must attract and retain qualified employees. It does so, in part, by compensating employees at "market competitive" levels, meaning that SEMCO pays employees compensation (in the form of salary, benefits, and other forms of compensation) based on market survey data. While some employers have a different approach, SEMCO's objective is to pay employees at the middle of the market (the 50th percentile). In addition, as reflected in compensation surveys, a portion of the compensation paid to executive level employees is typically "at risk" and takes the form of common stock based awards.

Q. Please continue.

A. Aside from the fact that surveys demonstrate that such awards are typically a component of compensation and thus necessary to attract and retain qualified and experienced utility executives, the primary rationale for making such awards is a belief that such awards provide an added incentive for above-average performance. SEMCO believes that paying market competitive salaries, benefits, and common stock-based awards are thus in the best interest of customers. For instance, while the performance criteria for these awards typically focus on corporate-level performance, those criteria encourage behavior such as controlling costs, because controlling costs influences corporate financial performance directly. Controlling costs also benefits customers, since reducing the costs of providing service to customers ultimately reduces customer rates below what those rates would otherwise be.

Q. Is the compensation paid to SEMCO employees fair and reasonable?

A. Yes. In its effort to tie its compensation program to market data, SEMCO benchmarks and prices jobs individually, by position, utilizing gas utility peer group and nationally recognized market survey data. Several comparable natural gas utility and energy industry data points are incorporated in this process, and geographical differences are addressed where appropriate. Further, the data is segmented by size, revenue, and employee count. Again, the objective is to compensate employees at the middle of the market and not some higher level, so SEMCO prices each individual job at the 50th percentile of "market consensus," rather than the more common 75th or 90th percentiles. The total compensation figures produced by this analysis are typically comprised of two interrelated components, depending on the job being analyzed; namely, cash compensation (base salary plus annual incentive compensation) and equity-based compensation of the sort summarized in my schedule of stock-based compensation. (As noted earlier, employee benefits are benchmarked to the middle of the market in the same way.) Customers benefit directly, of course, when SEMCO is able to attract and retain qualified and experienced employees at all levels.

LOST AND UNACCOUNTED FOR GAS

Q. Is there anything else you wish to discuss?

A. Yes. In her testimony, Ms. Gardiner is proposing that SEMCO Gas collect Lost and Unaccounted-for ("LAUF") gas costs through the Gas Cost Recovery ("GCR") process, in order to better match the Company's recovery of LAUF gas costs to the actual costs incurred by the Company. I will discuss how LAUF gas costs are accounted for, including my view that these costs are part of the cost of gas.

Q. How are LAUF gas costs currently accounted for in the GCR process?

A. First, the Company records all gas costs in its cost of gas accounts. These costs include gas commodity costs, storage, demand and transportation cost and other amounts directly related to the cost of gas.

These costs include the cost of gas sold to customers, Company use gas costs and LAUF gas costs.

Q. Please continue.

A. Second, during the monthly calculation of the GCR over-or under-recovery of gas costs, an estimate of LAUF gas volumes is made and valued at the average cost of gas for the GCR plan period. This amount is then removed from the Company's booked cost of gas. This is the methodology for complying with the Company's GCR tariff, which currently excludes LAUF gas costs from being recovered in the Company's GCR rates.

Q. Please describe in detail how the GCR process "prevents" LAUF gas costs from being recovered.

A. As part of my testimony, I have included an example in Exhibit A-9, Schedule C-14, Accounting For Lost and Unaccounted For Gas Costs, to illustrate how LAUF gas costs are excluded from GCR recovery, from an accounting perspective. In this exhibit, lines one through seven lay out a simple example of a month's activity. In this exhibit, the Company has purchased gas, and, because it loses a percentage of this gas as part of the physical process of delivering it to customers, has sold slightly less gas than the amount originally purchased. Lines eleven through seventeen show how the monthly GCR reconciliation process currently works, which, as I suggested in framing this question, "prevents" the Company from recovering all of the gas cost that is originally booked to cost of gas sold in the GCR rate. Lines 21 through 27 show the accounting entries from this part of the process. Lines 29 through 33 show the impact of this accounting on the Company's income statement and how LAUF is part of the accounting for cost of gas sold.

Q. Please continue with your explanation.

A. As a result of not being able to recover LAUF gas costs as part of the GCR process, in this example, the Company incurred a loss. This example also shows that the loss would increase when gas prices exceed

the price used to determine the allowance for LAUF gas costs in base rates.

PENINSULAR GAS COMPANY ADJUSTMENT

Q. Please discuss Exhibit A-9, Schedule C-18, Peninsular Gas Company O&M Expense Adjustment.

A. On June 1, 2005, SEMCO Gas acquired the assets, and in accordance with the order in Case U-14392, began providing natural gas service to the former customers of Peninsular Gas Company. Beginning on June 1, 2005, the Company combined all of the Peninsular Gas operations with the operations of SEMCO Gas. Because the operations were combined, there was no adjustment necessary to include Peninsular Gas Company operations and maintenance expenses, in this rate case, from June 1, 2005 forward.

Q. Please continue.

A. In John Alger's testimony, in Exhibit A-11, Schedule F-2, he normalizes the inclusion of Peninsular Gas Company's revenues, for the period January 1, 2005 through May 31, 2005, before Peninsular Gas's assets were purchased. The schedule I prepared normalizes the operations and maintenance expenses for Peninsular Gas Company for the period January 1, 2005 through May 31, 2005.

Q. Please continue.

A. SEMCO Gas received a copy of the financial statements of Peninsular Gas Company, for the period January 1, 2005 through April 30, 2005, from the previous owners. In column A of the schedule I created, lines 2 through 28 show the actual expenses recorded by Peninsular Gas Company through April 30, 2005. I divided each expense by four to determine a monthly average which is shown in column B. I then multiplied those amounts by five to estimate the operations and maintenance expenses through May 31, 2005. That total is shown on line 29 in Column C.

Q. Why are there deductions to this total?

A. The Company did not retain all of the employees of Peninsular Gas Company and it did not purchase all of its facilities. So I removed the salaries and benefits of the employees who were not retained and removed the rent costs for the facilities that were not needed. As a result, line 42, Column C, shows the final adjustment made to normalize the Peninsular Gas Company's operations and maintenance expenses as if SEMCO Gas had owned and operated this facility for all of 2005.

Q. Does this conclude your direct testimony at this time?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to redesign and increase	)	Case No. U-14893
its rates for the sale and transportation	)	
of natural gas in its MPSC Division and	)	
for other relief.	)	
	)	

DIRECT TESTIMONY AND EXHIBIT OF TIMOTHY J. LUBBERS

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 2006

Testimony of Timothy J. Lubbers
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. Timothy J. Lubbers, 1411 Third Street, Suite A Port Huron, MI 48060.

Q. By whom are you employed and what is your present position?

A. I am employed by SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc., as its Director of Marketing and Corporate Communications.

Q. Please describe your educational background and business experience.

A. I graduated from the University of Missouri in December 1989 with a Bachelor of Science degree in Mechanical Engineering. Between 1990 and 1991, I worked as a Consulting Engineer with Booker Associates in St. Louis, Missouri. At that time, my responsibilities included designing heating and cooling systems for commercial buildings. In 1991, I left Booker and took a position with KPL Gas Service in Kansas City, Missouri, as a Commercial Sales Engineer. My responsibilities at KPL Gas Service included calling on commercial and small industrial customers to promote the use of natural gas for heating, cooling and dehumidification. In 1994, I left KPL Gas Service to take a position with Missouri Public Service as a Commercial Energy Engineer. In this role, I called on commercial and small industrial customers to promote the use of natural gas and electricity in a variety of applications. Missouri Public Service is owned by Aquila (formerly UtiliCorp) and, in 1994 I was promoted to an Account Executive position with one of Aquila's unregulated affiliates, UtiliCorp Energy Solutions. In this capacity, I sold gas to large commercial and industrial customers.

I joined SEMCO Gas in 1996 as the Director of Key Accounts in the Marketing Department, to manage the function dedicated to working with SEMCO Gas's largest customers. In 1998, I assumed the broader role of

Director of Marketing, managing all aspects of marketing at SEMCO Gas, from residential through large transportation customers. In mid-2004, I assumed responsibility for Corporate Communications, in addition to marketing, and continue in that role today.

Q. What are your responsibilities as Director of Marketing and Corporate Communications?

A. I am responsible for all of SEMCO Gas's marketing and communications efforts. This includes (1) administering the Company's Customer Attachment Program ("CAP") efforts, to market natural gas in parts of the Company's service territory where substantial new development is occurring; and (2) marketing natural gas or transportation services to the Company's largest customers. In addition, I am responsible for creating and distributing all internal and external communications for SEMCO Energy, Inc.

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

A. The purpose of my testimony is to propose a comprehensive Customer Efficiency and Conservation Plan, propose an interruptible transportation rate, and explain why SEMCO Gas negotiated a special Transportation Contract with one of its transportation customers.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. Exhibit A-12, Schedule 1, is SEMCO Gas's proposed Customer Efficiency and Conservation Plan. This exhibit was prepared by me or under my direct supervision. I discuss this exhibit later in my testimony.

Q. Have you testified before the Michigan Public Service Commission (the "MPSC" or the "Commission") before this case?

A. Yes. I have testified before the MPSC in SEMCO Gas's previous general rate case as well as other kinds of proceedings.

Customer Efficiency and Conservation Plan

Q. Please describe the background for SEMCO Gas's proposed Customer Efficiency and Conservation Plan.

A. In October of 2005, the MPSC directed the MPSC Staff to review energy efficiency programs and to "recommend alternatives designed to improve energy efficiency, make energy utility services more affordable to Michigan rate payers, and enhance the State's economy." This directive was given as part the MPSC's Order in Case No. U-14667. In response to that directive, Gary Kitts, on behalf of the MPSC Staff, prepared a report containing the MPSC Staff's recommendations. In that report, Mr. Kitts stated that the MPSC Staff did not believe that it was appropriate for the Commission to design individual utility energy efficiency and conservation programs. Rather, Mr. Kitts proposed that the Commission would set basic standards for such programs. As I understand it, the intent was for the State's utilities to propose programs that fit their particular circumstances and met these standards.

Q. What standards did Mr. Kitts suggest the Commission consider in his report?

A. The basic standards suggested in his report were: (1) programs should be available to all customer classes and be reasonably proportionate to the size of the classes, (2) programs should be efficient from an energy savings perspective, (3) programs should be efficient from an administrative perspective, (4) programs should be designed to provide efficiency measures targeted to appropriate customer groups, and (5)

programs should be designed to be continuing in nature rather than "start and stop" affairs.

Q. Against this backdrop, what has SEMCO Gas done in connection with this proceeding?

A. SEMCO Gas has developed a comprehensive Customer Efficiency and Conservation Plan that meets these standards, taking into account the Company's particular circumstances. The Company's proposed program is described in the plan attached as Exhibit A-12, Schedule 1. This Customer Efficiency and Conservation Plan focuses on six key components:

1. Education – Customer education has the potential to be the single biggest contributor to conservation. Communication is proposed, using a variety of media, about multiple conservation techniques, targeted toward SEMCO Gas's residential customers, who comprise 91% of the Company's customer base. SEMCO Gas's service territory is not contiguous and spans from Southeastern Michigan to Southwestern Michigan and portions of Michigan's Upper Peninsula. The geographic dispersion of customers does present certain challenges when trying to communicate any sort of messages. No single print outlet, television or radio station covers a majority of SEMCO Gas's territory. Therefore, the Company has developed an education strategy for its conservation messages that combines some radio and newspaper communications, with other communications tools (such as bill inserts, customer forums and web-site information). This education plan will provide a consistent message about conservation, yet be flexible enough to accommodate changes in efficiency and conservation tools, the

programs available from the Company and others, and new technologies.

2. Analysis – Analysis is an important component of improving energy efficiency and encouraging conservation. SEMCO Gas proposes to provide a "Do-It-Yourself" energy audit kit that should provide individuals with the information needed to evaluate the energy conservation potential in their homes. In addition, the Company proposes to refer customers to companies and agencies that provide energy audits for residential customers. Many Community Action Agencies ("CAAs") provide energy audit services, as do privately-owned companies. SEMCO Gas proposes to rely on these third-party resources to provide audit services to Company customers. Because residential customers do not typically differentiate their energy use by fuel type and instead want the "whole picture," these audits will focus on potential electricity savings, as well as natural gas savings, and should provide quantitative information about energy savings measures before and after implementation.

3. Measures – The selection of energy efficiency and conservation measures will be directed, in part, by the results of the energy audits. In addition, to the extent funded by the Commission in rates charged to Company customers, SEMCO Gas proposes to support the implementation of certain energy efficiency and conservation measures by funding rebates and subsidizing the cost of certain other items. For example, SEMCO Gas proposes to offer a one-time $200 rebate to customers who install a furnace with an Annual Fuel Utilization Efficiency ("AFUE") rating of at least 90 percent. As another example, SEMCO Gas proposes to develop and distribute an energy conservation kit, similar to the "Save Energy with Ease" program initiated by the

MPSC and Governor Granholm in 2006 and funded by DTE Energy, Consumers Energy Company, Indiana Michigan Power Company, and SEMCO Gas. This program, which funded conservation seminars and free energy conservation kits, was filled to capacity within two days of its introduction. This response demonstrates the desire among Michigan residents for more information on energy efficiency and conservation and access to energy-saving products and services.

4. Tracking – Analyzing and tracking individual customer consumption, before and after energy conservation measures are implemented, is a relatively simple and straightforward method to determine the effectiveness of conservation efforts. SEMCO Gas currently maintains information about the weather in its various operating areas and can "weather normalize" consumption based on historical information. Assuming that funding is adequate, SEMCO Gas proposes to provide all customers an annual energy efficiency report. This report will provide weather-normalized customer consumption data and tell customers how more or less efficiently a customer is using energy compared to the previous year. This individualized approach will allow SEMCO Gas to monitor the impact of particular customer efficiency improvements, to the extent that SEMCO Gas either knows of, or participates in, the improvements. In addition, this approach will allow those customers who initiated energy improvements without SEMCO Gas's involvement to monitor the effectiveness of their efforts.

5. Financing - SEMCO Gas currently has a financing program for qualified dealers, to help customers who are purchasing a furnace or related equipment finance their purchase. If desired, this financing program can easily be extended to provide financial

support that will induce customers to choose more efficient equipment. As an example, according to one heating and cooling contractor doing business in SEMCO Gas's service territory, a typical replacement of an existing furnace would cost approximately $2,840. Upgrading the same installation to a furnace with an AFUE of greater than 90 percent would cost approximately $3,290. This incremental $450 or 16 percent increase is significant to many SEMCO Gas customers, who are typically concerned about their initial out-of-pocket cost for such a purchase. This type of installation will benefit from rebates to defray the higher cost and encourage the installation of the more efficient furnace, because that extra up-front cost will be paid back over time in the form of energy savings.

6. LIEEF Funding -The Customer Choice and Electricity Reliability Act of 2000, 2000 PA 141, authorized the creation of a Low-Income Energy Efficiency Fund ("LIEFF"), administered by the MPSC. This fund was created to provide shut-off and other protection for low-income customers and to promote energy efficiency and conservation by all customer classes.

This fund was originally funded entirely by DTE Energy from revenues related to "securitization." Although DTE Energy solely funded LIEEF, all Michigan residents were eligible for the benefits of LIEEF, regardless of their energy provider. Recently, the MPSC Staff said in Case Number U-14547 that Consumers Energy should participate in the funding of LIEEF, in addition to DTE Energy. The funding level for both companies was established at the equivalent of two percent of commercial and industrial revenues.

LIEEF is a state-wide program focused not only on low-income assistance, but also on energy efficiency and conservation. In fact, the MPSC said in the Consumers Energy case that, to the extent possible, funding should be shifted away from energy financial assistance and towards energy efficiency and conservation.

SEMCO Gas believes that it is appropriate for its customers to participate in the funding of this state-wide program to promote energy efficiency and conservation. SEMCO Gas's total revenues are listed in John Alger's testimony Exhibit: A-11, Schedule F-3 as $80,782,196. Subtracting residential customer revenue of $54,754,050 from the total revenue produces commercial and industrial revenue of $26,028,146. Two percent of this number is $520,563. SEMCO Gas proposes to fund LIEEF at this amount of $520,563 as part of its total Customer Efficiency and Conservation Plan.

Q. Did you develop the Company's proposed customer efficiency and conservation plan attached as Exhibit A-12, Schedule 1?

A. Yes.

Q. How did you develop this plan?

A. In addition to being generally familiar with such programs, I reviewed two national studies referenced in Mr. Kitts' report, "Meeting Essential Needs: The Results of a National Search for Exemplary Utility-Funded Low-Income Energy Efficiency Programs" American Council for an Energy Efficient Economy, September 2005 and "Examining the Potential for Energy Efficiency To Help Address the Natural Gas Crisis in the Midwest" American Council for an Energy-Efficient Economy, January, 2005. In addition to reviewing these documents, I and members of my staff

evaluated communication tools, met with local CAAs and energy efficiency and conservation experts, and researched readily available conservation tools and resources. Mr. Ketchum, another witness in this case, was also consulted. He describes some of the conservation programs offered in the 1970s, 1980s and 1990s in his testimony and the lessons learned from those programs. In particular, I understand Mr. Ketchum's testimony to say that the complex nature of tracking and cost recovery associated with those earlier programs was cumbersome and caused controversy.

Based on this work, different approaches were considered, conservation estimates evaluated, and the attached plan was finalized. It should be noted that this plan should continue to evolve as the Company evaluates the effectiveness of individual plan components and as technology and energy efficiency and conservation measures change and improve.

Q. What is the cost of this new Customer Efficiency and Conservation Plan?

A. The plan, in its current form, estimates the cost of a comprehensive Customer Efficiency and Conservation Plan to be $2,045,563 (shown on page 16 of Exhibit A-12, Schedule 1). However, the plan is comprised of a variety of independent components. These components can be eliminated, expanded or modified to satisfy the MPSC's preferences. Also, this plan assumes that the Commission will adopt the Company's proposed residential rate design, so it does not address the issue of whether and how the Company should be compensated for lost revenues associated with energy efficiency and conservation measures funded by the plan. The ability to avoid dealing with the lost revenues issue is an example of the alignment of interests that the Company's proposed fixed monthly service charge rate design produces.

Q. How do you expect this conservation plan will benefit SEMCO Gas's customers?

A. The most significant benefit I expect customers to realize is lower overall energy costs. Easy access to energy efficiency and conservation information, products, and services should allow many customers to reduce their energy consumption significantly. As natural gas prices increased in 2005 and customers started seeing the impact of higher natural gas prices in their monthly bills, customers appeared to take steps to reduce consumption in a more comprehensive way. Mr. Alger's testimony discusses this trend. The plan is intended to assist all residential customers in reducing their consumption by providing information and providing financial support for "pro-conservation" decisions, in a systematic way.

Q. How does SEMCO Gas currently promote conservation?

A. SEMCO Gas currently distributes conservation "tips" in its bi-monthly bill insert publication entitled Connectivity. In addition, SEMCO Gas has distributed information prepared by the U.S. Department of Energy regarding energy conservation at home shows, senior citizen events, and other community gatherings. SEMCO Gas representatives regularly appear on local radio and television programs to discuss natural gas prices, conservation, and sources of assistance.

Q. How does the proposed Customer Efficiency and Conservation Plan satisfy the five standards recommended by Mr. Kitts?

A. Mr. Kitts's first recommended standard states that programs should be available to all customer classes and be reasonably proportionate to the size of the classes. SEMCO Gas's proposed plan addresses residential customers initially, consistent with the Company's rate design proposal in this case. As noted by Ms. Gardiner in her testimony, SEMCO Gas's residential class represents over 90 percent of its customers and, therefore, the Customer Efficiency and Conservation Plan proposed by the Company is focused on residential customers. In addition, residential

conservation techniques and products tend to be applicable to a large cross-section of this market segment. Insulation, caulking, efficient appliances, and similar improvements are applicable in most residential homes and therefore can be promoted and implemented in a uniform fashion.

The second standard recommended by Mr. Kitts is that programs should be efficient from an energy savings perspective. This plan encourages customers to perform, or have performed, an energy audit to determine which individual efficiency measures to employ. A focus on identifying individual requirements will ensure that energy efficiency measures are appropriate for the customers in their individual circumstances.

The third standard recommended by Mr. Kitts is that programs should be efficient from an administrative perspective. SEMCO Gas's Customer Efficiency and Conservation Plan contemplates the addition of only one additional staff member and relies heavily on existing CAAs and vendors to implement much of the work. This approach will minimize any duplication of effort and will utilize those individuals and organizations best able to implement efficiency measures.

The fourth standard recommended by Mr. Kitts is that programs should be designed to provide efficiency measures targeted to appropriate customer groups. As stated earlier, this plan targets its education campaign toward residential customers and leverages participation with CAAs to provide access to customers with significant need.

The fifth standard recommended by Mr. Kitts is that programs should be designed to be continuing in nature rather than "start and stop" affairs. The Company has devised a flexible plan that can be easily modified as technology changes and regulatory priorities evolve. SEMCO Gas also proposes to review the effectiveness of its energy efficiency and

conservation plan annually and propose potential changes as the situation warrants.

Q. Are there any other considerations the Company believes the Commission should consider with respect to the proposed plan?

A. It is important, as Ms. Gardiner notes in her testimony, that the Commission fund the Company's energy efficiency and conservation activities via appropriate ratemaking treatment of the substantial costs the Company proposes to incur. In addition, prior attempts to encourage utility-sponsored efficiency and conservation programs were complex and sometimes controversial. The details of these programs and some lessons learned from prior experiences are discussed in Mr. Ketchum's testimony. In short, the programs implemented in the 1970s through the 1990s required significant administration and regulatory action and in some cases were controversial. The Company's plan strives to simplify the process, such that the actual costs of the conservation and efficiency plan are recovered through a fund financed by customers. The details of this recovery mechanism are discussed in Ms. Gardiner's and Mr. Alger's testimony.

Interruptible Transportation Contract

Q. Please describe the Interruptible Transportation Rate that the Company is proposing.

A. SEMCO Gas is proposing to add an interruptible rate for certain transportation customers. This rate would be available to only those transportation customers who meet the following criteria. First, customers must be located in an area of SEMCO Gas's service territory that is experiencing, or is likely to experience, a system constraint preventing the Company from delivering natural gas to all customers in that area. Second, customers must have the demonstrated ability to switch their

entire load to an alternate fuel. This means that customers must have the equipment necessary to use this alternative fuel and such equipment must be in good operating condition, with all required environmental and other permits and licenses. This also means that customers must have the means for acquiring and storing a sufficient quantity of the alternate fuel to sustain a lengthy interruption of natural gas service.

Q. Why does SEMCO Gas want this service to be optional and offered at the discretion of SEMCO Gas?

A. In some cases, an upgrade of SEMCO Gas's system would be warranted, to ensure reliable service to all customers in the area, including the customer that might otherwise wish to be served on an interruptible basis. In such a case, SEMCO Gas believes it would be preferable to improve its system and include the costs of the upgrade in its cost of service. There may be other instances, however, in which a system upgrade may not necessarily be required, if a particular customer is willing to be interrupted and the improvement of the system is particularly costly or does not benefit a sufficient number of other customers. In that instance, it would be appropriate to allow certain customers to be offered an interruptible service at a reduced rate. This should provide a benefit to all customers; the interruptible customer enjoys a reduced rate and all other customers benefit from a lower cost of service, because SEMCO Gas did not expend capital and increase its rate base.

Q. What if circumstances change and it becomes appropriate to expand the Company's system?

A. As stated before, the first criteria for offering this rate is that the customer be located in an area that is likely to experience a system constraint. If a system constraint exists, or is likely to exist, and the Company takes action to remedy the situation, this interruptible rate would no longer be available to customers in that particular area.

Q. What do you propose to do if the customer is not able to switch to alternate fuel when required?

A. SEMCO Gas's transportation tariff currently includes language to penalize customers for unauthorized consumption of natural gas. This penalty structure should be sufficient to manage this situation. Specifically, transportation customers are required to balance daily through the use of SEMCO Gas's Natural Nom system. This system requires the customer or its authorized representative to submit daily nominations for its expected use. During the interruption period, the customer would be required to limit all or a specified portion of their natural gas consumption. If the customer continued to consume natural gas, the penalties would be assessed as already defined in SEMCO Gas's tariff. In extreme cases, SEMCO Gas may be required to physically turn off service to the customer during the interruption to maintain system integrity. Once the constraint had passed, SEMCO Gas would then investigate the situation to determine the continued availability of the interruptible rate for this customer.

Q. Has SEMCO Gas experienced a system constraint where this type of rate would be helpful?

A. Yes, in January 2005, SEMCO Gas had difficulty maintaining appropriate pressures on its distribution system in Houghton, Michigan. One of SEMCO Gas's transportation customers, Michigan Technological University ("MTU"), was able to switch from natural gas to an alternate fuel and pressures were stabilized. This incident prompted discussions between MTU and SEMCO Gas to determine what could be done to improve the system in the area. SEMCO Gas developed a way to improve system reliability, but at a cost of approximately $2 million. After reviewing the proposed system improvement and related costs, SEMCO Gas and MTU explored other options and determined that a reduced

transportation rate coupled with the ability to interrupt would allow both parties to achieve significant savings.

Q. What rate is the Company proposing?

A. The rate the Company is proposing is a fixed monthly customer charge and remote meter charge consistent with the Company's TR-3 rate schedule of $3,000 per month and $75 per month respectively, a distribution rate of no less than $0.3398 per Dth on peak and a distribution rate of no less than $0.1898 per Dth off peak. This rate is consistent with the cost of service developed for MTU by Mr. Ketchum, Exhibit A-11, Schedule F-6, as an interruptible customer. Additionally, providing a floor for this type of rate structure will allow SEMCO Gas to negotiate appropriate terms for other instances and will prevent excessive discounting or abuse. This rate is detailed in the proposed tariff sheets shown in Exhibit A-11, Schedule F-8, pages 11 and 12.

Q. Would SEMCO Gas be amenable to an alternative treatment of the net revenues associated with this interruptible service?

A. Yes. The Company has relatively few commercial and industrial customers, and the proposed interruptible rate is a new service classification for SEMCO Gas. I am aware that, due to the nature of interruptible service, net interruptible revenues are sometimes credited to firm customers for ratemaking purposes, generally because firm customers bear the fixed costs of the SEMCO Gas system. The Company would be amenable to treating the net revenues from interruptible customers under the proposed service classification in this fashion, as long as the Company's revenue requirement was adjusted appropriately and a workable mechanism for crediting the net revenues to firm customers was developed. At this point, given the relatively small amount expected to be associated with service provided under this new rate classification, the Company did not take that approach in this case.

Transportation Contract

Q. In his 2005 Cost of Service Study, Mr. Ketchum has included a Special Contract Customer. Are you familiar with this customer?

A. Yes.

Q. Please explain why SEMCO Gas negotiated a special contract with this customer?

A. Periodically, municipalities in SEMCO Gas's service territory try to find ways to lower costs to residents and businesses in their areas. In some instances, these municipalities have threatened to build their own natural gas pipeline and/or condemn SEMCO Gas facilities to bypass SEMCO Gas and serve their residents directly. In most cases, SEMCO Gas works closely with the local officials to help them understand the total cost of service and all that is involved in supplying natural gas to customers. As they come to understand all of the costs and issues involved, the idea of bypassing the Company is usually resolved without further action.

In 1999, the City of Zeeland stated a similar desire to serve some of the larger industrial customers located within its city limits and took the position that it could do this by constructing a natural gas transmission line from ANR Pipeline to the City's industrial park. These industrial customers are located in an area approximately 2 miles from ANR Pipeline. SEMCO Gas met with Zeeland officials to discuss the situation. City officials wanted to explore the possibility of building a pipeline and proposed a ballot initiative that asked the voters of Zeeland to authorize an analysis of potential for creating a City-owned– and -operated natural gas utility. In November 1999, the residents of Zeeland passed this ballot initiative, and the City began the process of evaluating the ways in which to serve the industrial park load. The City retained an engineering firm to perform a preliminary analysis of the project. This cost study indicated that the project could be economically completed and at least 13 of

SEMCO Gas's largest customers in the area with an average annual load of 968,000 Dekatherms could be served by the City instead of by SEMCO Gas. The 13 customers listed in Zeeland Board of Public Work's letter represent approximately $600,000 in annual margin for SEMCO Gas.

This information was provided to SEMCO Gas in an April 28, 2000 letter from the Zeeland Board of Public Works. In this letter, the Zeeland Board of Public Works also responded to SEMCO Gas's request that the Company be allowed to respond to the bypass proposal. A main Company consideration was to avoid losing the margin from these customers, because that margin helps cover the Company's fixed costs of providing service and would be allocated to other customers if these City of Zeeland area customers left the system. SEMCO Gas began working with the largest of these industrial customers to develop a contract attractive enough to keep this customer on SEMCO Gas's system. This Transportation Contract Customer represents approximately 43 percent of the transportation margin of the 13 customers.

Q. Was the special contract with this Transportation Contract approved by the Commission?

A. Yes, in an order dated March 29, 2001, in MPSC Case No. U-12812, the MPSC approved the contract.

Q. In that order, did the Commission address the future ratemaking treatment of the cost of providing service pursuant to the contract?

A. Yes. In that order, the Commission stated that it would not make a definitive ruling on the future ratemaking effects of the contract but discussed the general principles that should guide future Commission action and the burden imposed on the Company, stating:

> …The burden would require, at a minimum, a clear, convincing, and unequivocal demonstration either (1) that the contract prices and terms are justified on the basis of cost of service, or (2) that the benefits for other (non-participating) ratepayers are substantial and have a value that outweighs the cost that are not recovered from the contract customer….

Q. Does the contract to provide service to this customer satisfy this standard?

A. Yes, in several respects. First, this customer and 12 others covered by the City's proposal had demonstrated the willingness, ability and economic viability of bypassing the Company's system. If the contract had not been entered into with the largest of these customers, it is likely that this customer and other customers would have elected to bypass the Company's system, as proposed by the City. In that event, the Company would have lost approximately $600,000 in annual margin, which offsets costs that would otherwise be borne by other customers. The preservation of these contributions to fixed cost recovery is many times greater than the discount provided under the contract. (The value of the discount to this particular customer is approximately $104,000 annually.) Furthermore, the rates charged under the contract are within the range of rates permitted by the Company's gas transportation tariff for customers with other (fuel/coal) displacement ability.

SEMCO Gas's transportation tariff states:

> If the Gas to be transported is an incremental load which will be used to displace coal or coal derived fuels and will be delivered during a time when the Company has sufficient capacity, then the Transportation Rate for such incremental load shall be a rate, as negotiated between the Company and the Shipper, between a floor of $0.05 per Dth and a ceiling price equal to the full rate shown on the applicable rate schedule. The Shipper shall also pay all applicable surcharges for all gas delivered and all applicable BRCs for all Dth of Daily Imbalance created by the shipper. The minimum charge for such coal displacement service shall be the monthly Customer

> Charge and Remote Meter Charge. All coal displacement volumes are interruptible by the Company. Coal displacement volumes are excluded for purposes of determining a Shipper's MDQ and FBT.

The negotiated rate for this customer is $0.28 per Dth, which falls between the specified floor of $0.05 per Dth for Coal displacement customers and the ceiling of the full rate shown on the applicable rate schedule, which is $0.5613 per Dth on peak and $0.4113 per Dth off peak.

Q. Why should the Commission allow SEMCO Gas to recover the discount associated with this contract?

A. Not to recognize the costs of providing this service in rates would unfairly pass along to other customers the significantly greater benefits of the Company's actions (namely, retention of approximately $600,000 in margin), while imposing the costs thereof (namely, approximately $104,000 discount compared to the published transportation rate).

Q. Does this complete your direct testimony at this time?

A. Yes.