STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to increase its rates and for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY OF DANIEL J. FORSYTH

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Daniel J. Forsyth
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

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

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

A I am employed by SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc. ("SEMCO"), as Vice President of Business Services.

Q What are your responsibilities as Vice President of Business Services?

A I am responsible for the Gas Supply, Gas Control, Regulatory, Government Affairs, Marketing and New Customer Additions and Facilities activities for the Company.

Q. Would you briefly describe your educational background?

A. I obtained a Bachelor of Science in Civil Engineering from Michigan Technological University in 1982.

Q. Please summarize your employment and professional experience.

A. I have held positions of increasing responsibility, in the areas of field operations, engineering, customer service, and support services at SEMCO Gas since 1982. I am a registered professional engineer in the State of Michigan. I participated in the Operator Qualification Training Program Development and various American Gas Association Committees including Chair of the Utility and Customer Field Services Committee.

Q. Are you sponsoring any exhibits with your direct testimony?

A. No, I am not.

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

A. The purpose of my direct testimony is to provide an overview of the Company's general rate case filing, including a summary and discussion of the primary drivers. I will also generally discuss, from a policy perspective, certain issues addressed in the direct testimony and exhibits of other Company witnesses. Finally, I will provide an introduction to the Company's witnesses and topics they will be supporting.

Q. Discuss SEMCO Gas's business objectives and how it has met those objectives.

A. SEMCO Gas endeavors to serve its customers with reliable and affordable natural gas service and do so in a safe manner while recouping its cost of service, including a reasonable return on its investments. SEMCO Gas has been able to provide a high level of service to its customers, while not applying for a general rate increase for over nine years. SEMCO Gas's Main Replacement Program ("MRP") is a great example of providing cost effective, safe and reliable service to customers. Under AltaGas's leadership, SEMCO Gas has been able to not only maintain, but increase the significant capital investment in the MRP. The original program was approved by Commission order in January 2011. Later the Company doubled the program's size and expanded it to include vintage plastic pipe and extended it through 2020. With a focus on safety, significant capital investments, and operational cost containment over the last nine years, it is now time to reset rates and allow SEMCO Gas to recover its reasonable costs and earn a fair return on these capital investments. SEMCO Gas intends to continue this focus on safety and reliability of service and invest the needed capital. This general rate case filing includes not only recovery of Operational and Maintenance ("O&M") expense increases and for capital already invested, including the Marquette Connector Pipeline ("MCP"), but also asks for an extended MRP and a new Infrastructure Reliability Improvement Program ("IRIP").

Q. Please provide a general overview of the Company's requests in this filing.

A. SEMCO Gas is seeking an annual base rate increase of $38,114,307 for the projected 12-month period ending December 31, 2020. This rate increase request is based on the historical calendar year ended December 31, 2018, as normalized and adjusted for known and measurable changes. The requested rate increase is primarily driven by capital investments and the associated depreciation and property tax increases. Increased O&M expenses are another contributing factor. Overall, capital investment in infrastructure and related expenses, comprises 75% of the Company's rate relief request. Most notably, SEMCO Gas is in the process of constructing the MCP as previously approved by the Commission in Case No. U-18202. SEMCO Gas is also requesting to extend the highly successful MRP for the period of 2021 through 2025, and to reflect the MRP investment from 2011 through 2020 in rate base. In addition, SEMCO Gas is requesting various tariff changes including a significant update to the tariff book's transportation section and the adoption of additional low income programs intended to help support the Company's most vulnerable residential customers. Lastly, SEMCO Gas is requesting approval of a new IRIP and related surcharges.

Q. Please summarize the primary drivers of the Company's requested rate relief.

Key Drivers: Revenue Impact		
	Drivers	Revenue Requirement Impact ($ Millions)
a.	Rate Base	$48.7
b.	Operating Expense	$16.0
c.	Sales Revenue and Other	-$23.9
d.	Calculation C U-20311	-$2.7
e	Total Revenue Requirement Impact	$38.1

Q. When did SEMCO Gas last increase its base rates?

A. The Company's last general rate case, Case No. U-16169, was filed on June 29, 2010. On January 6, 2011, the Commission approved a settlement agreement resolving all issues in the case. As part of the settlement SEMCO Gas was authorized to increase its base rates in the annual amount of $8,100,000 effective on and after the day following the issuance of the order approving the settlement agreement. The order approving the settlement agreement also authorized the Company, among other things, to implement its MRP.

Q. Why has it has been 9 years since the Company's last general rate case filing?

A. Since the issuance of Commission's order approving settlement agreement in Case No. U-16169, the Company has worked diligently to control expenses and target capital investment toward the highest needs for redundancy, reliability and customer growth. This focus on cost control and targeted capital investment has benefited customers through less frequent general rate cases and lower overall monthly bills. In Witness Mark Moses's testimony he highlights that SEMCO Gas's O&M expenses have only increased by a Compound Average Growth rate ("CAGR") basis of less than 0.23% from 2009 to 2018. In Witness Katie Singer's testimony, she discusses the cost effectiveness of the MRP program as well as the impact on safety to customers and employees. Further, the ability to earn on the Company's investment in the MRP not only improved the safety and reliability of SEMCO Gas's service to its customers, but also helped the Company stay out of general rate cases for a significant period of time. In Witness Ann Forster's testimony she discusses the Company's employee compensation philosophy, which not only targets the middle of the market for total compensation, but also includes incentive compensation programs to incentivize good decision processes to promote efficient, effective, and customer driven operations. As stated in Company financials, SEMCO Gas has been very effective in containing costs to the benefit of the customer. Additionally, since its last rate case, SEMCO Gas's customer count has increased by 8% while the Company's overall O&M expense has increased by only 2%; the combination of this has the effect of virtually eliminating any inflationary impact on SEMCO Gas's customers for almost a decade. Moreover, while being efficient with expenses, SEMCO Gas has been able to maintain excellent safety and customer satisfaction metrics. Specifically, the Company's leak response time has been consistently below 25 minutes and customer satisfaction has been above 90% during this timeframe. Finally, SEMCO Gas has received the American Gas Association ("AGA") Industry Safety Leader Award 8 out of the last 11 years.

Marquette Connector Pipeline

Q. Please describe the MCP.

A. The MCP is 42.6 miles of pipeline from the Great Lake Gas Transmission Company's interstate pipeline near Arnold, Michigan to SEMCO Gas's Marquette distribution system and Northern Natural Gas's pipeline near Marquette, Michigan. The Pipeline is comprised of two segments. The first segment consists of 36.2 miles of pipeline connecting GLGTC's interstate pipeline to NNG's pipeline near Marquette, Michigan. The second segment consists of 6.4 miles of pipeline from segment one into SEMCO Gas's Marquette distribution system. The Commission in its August 23, 2017 order approving settlement agreement in Case No U-18202, among other things, approved SEMCO Gas's request for authority to construct and operate the MCP, determining that when constructed and operated the MCP will serve the convenience and necessities of the public.

Q. What is the cost of the MCP?

A. As supported by Witness Ms. Singer, the Company projects that the final construction cost of the MCP will be $159,020,444. Including the associated expenses and rate of return, the overall revenue requirement associated with the MCP in this case is approximately $21 million. While the MCP is the single largest component of the Company's rate relief request in this case, the MCP is essential for reliability and redundancy in the Company's U.P. service territory.

Main Replacement Program

Q. Please describe the Company's MRP.

A. Originally approved by the Commission in Case No. U-16169 and subsequently updated twice in Case Nos. U-17169 and U-17824, SEMCO's Main Replacement Program has been an unmitigated success.

As supported by Witness Singer, SEMCO Gas has met or exceeded every requirement of the MRP since its inception in 2011, all while maintaining a low cost per mile. From 2011 through the end of the 2018 historical year, SEMCO Gas has replaced a total of 358 miles of high risk distribution main, including all of the Company's cast, wrought and ductile iron pipeline. From 2011 through 2018 (most recent data), corrosion leaks have decreased by 67% on an annual basis. In addition, the MRP has allowed for the accelerated replacement of Excess Flow Valves which automatically stop the flow of gas when a residential service line begins leaking. Also, concurrent with the MRP time period, the Company has eliminated all inside meters except for a few commercial accounts that have no other options.

Q. When does the current MRP end?

A. The most recent MRP was approved in Case No. U-17824 and is for the period of 2016 through 2020. However, as part of the settlement agreement in Case No. U-17824, the MRP surcharge will expire May 31, 2020, or when new rates are set in a general rate case proceeding. As a part of this proceeding SEMCO Gas is requesting to recover the MRP investment from 2011 through December of 2020 through bases rates.

Q. How has the MRP investment for the 2011 through 2020 period been included in Company's rate relief request?

A. Currently, the MRP investment and related expenses for the 2011 through 2020 period are being recovered through MRP surcharges. As a part of this filing, SEMCO Gas has included all of the MRP related cost into the normal revenue requirement calculation. These cost will be included in the Class Cost of Service model and allocated to the Company's customer classes as will any other rate base or expense item. Ultimately these cost will be recovered through the Company's distribution rates. When new rates are established the current surcharges will end.

Q. Is SEMCO Gas proposing a new MRP after the current program expires?

A. As supported by Witnesses Singer and McLean, SEMCO Gas is proposing an extended MRP for the 2021 through 2025 period with new surcharges beginning January 1, 2021, and continuing on until new rates are established in a future proceeding. SEMCO Gas believes that the MRP is the best way to replace facilities that present undue risk to the safety of SEMCO Gas's customers, employees and general public.

Q. Is SEMCO Gas proposing any changes from current MRP for the 2021 through 2025 period?

A. SEMCO Gas's proposal is to extend the current MRP and surcharge calculation methodology with one exception. Under the currently approved MRP, SEMCO Gas is required to retire 14.6 miles of qualified main annually under its normal capital budget. These are referred to as base miles in the Company's current program. The Company is requesting to end the base mileage requirement. As supported by Company Witness Singer, SEMCO Gas will shift funding to replace higher risk facilities that are currently not included in the MRP. This will allow the Company to use risk analysis to determine the best way to allocate funding under the normal capital budget.

Q. What is the expected MRP surcharge for a residential customer for the 2021 through 2025 period?

A. As supported by Company Witness McLean, SEMCO Gas is proposing a levelized monthly surcharge of $0.60 per meter for residential customers beginning January 1, 2021 and continuing unchanged until rates are set in a future proceeding.

<u>Infrastructure Reliability Improvement Program</u>

Q. Is the Company proposing an IRIP?

A. Yes. As a result of the Polar Vortex weather event in late January of 2019, Governor Gretchen Whitmer requested the Commission review the supply, engineering and deliverability of Michigan's natural gas, electricity and propane. SEMCO Gas has participated fully in this assessment process and, as Witness

Singer describes in more detail, performed a hazard analysis of SEMCO Gas's delivery system. As a result of that analysis, SEMCO Gas has identified certain system vulnerabilities and methods to mitigate those vulnerabilities. The proposed IRIP consists of projects designed specifically to address the vulnerabilities identified and recover the capital investment through a surcharge mechanism similar to our current and proposed MRPs. These projects are large in comparison to normal capital pipeline projects within our annual capital programs. Undertaking such capital intense projects without the proposed surcharge mechanism would require the Company to apply for rate relief annually and would extend the time required to complete the mitigation efforts. SEMCO Gas has been very successful in effectively utilizing and honoring the intent of approved surcharge programs such as MRP, reducing the need for and lengthening the time between general rate filings. It is SEMCO Gas's intent to achieve similar objectives through the proposed IRIP surcharge.

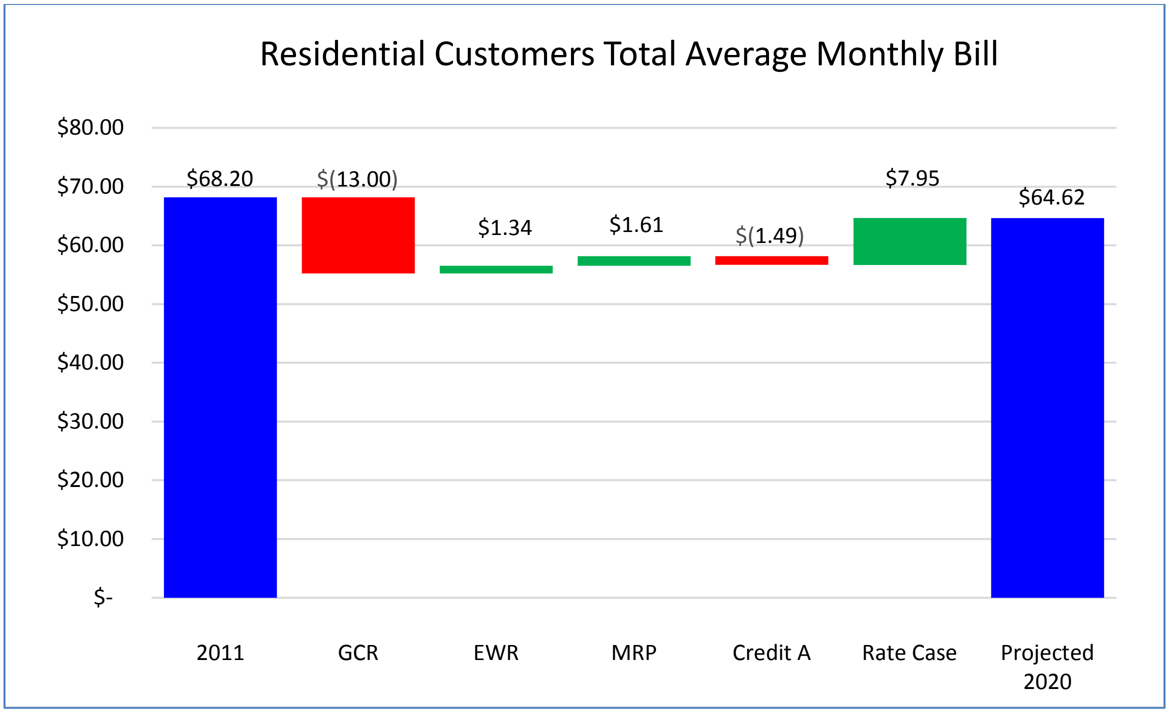
Q. What is the expected IRIP surcharge for a residential customer for the 2021 through 2025 period?

A. As supported by Company Witness McLean, SEMCO Gas is proposing a levelized monthly surcharge of $0.62 per meter for residential customers beginning January 1, 2021 and continuing unchanged until rates are set in a future proceeding.

<u>Customer Impacts</u>

Q. What is the projected impact of the requested rate increase for a typical residential customer?

A. A typical residential customer will see an increase of approximately $7.95 per month. However, due to lower GCR rates and the Company's efforts to control costs, a typical residential customer will have an overall lower bill when compared to 2011. The waterfall chart below illustrates the impacts of the 2011 through 2020 rate changes on an average monthly residential bill.



Q. Is the Company taking any steps to help mitigate the impact for low income customers?

A. Yes. The Company is proposing a new residential low income program. Witness Laurie Owens describes the Low-Income Assistance Credit program. This program specifically targets vulnerable low income customers to provide affordable payment options and decrease customer nonpayment disconnects.

Q. Are there any significant changes proposed to the Company's tariff not yet discussed?

A. Yes. Witness Walt Fitzgerald details the proposed changes to the Transportation Section E of the Company's Rate Book for Natural Gas Services. Of significance, the Company proposes to move to a daily cash out process. As explained by Witness Fitzgerald, the change will eliminate unnecessary complexity in the cash out process and minimize reliance on the Company's on-system storage for balancing gas consumption for transportation customers.

Q. Does the Company propose immediate adoption of the proposed changes?

A. No. Both the proposed changes and the Company's approach to cyber security require a software change. The software will be implemented during the projected test year and the proposed changes would take place immediately following.

Witness Summary

Q. What witnesses are appearing on behalf of SEMCO Gas in this proceeding and what is the subject matter of their pre-filed testimony?

A. The following witnesses are sponsoring pre-filed testimony on behalf of SEMCO Gas on the topics I describe:

- Jennifer L. Dennis –Witness Dennis will be sponsoring the Company's present revenue, rate design, including any adjustments to the cost of service study. Additionally, she will present an alternative revenue decoupling mechanism and various proposed tariff changes.
- Dr. Bruce H. Fairchild – Witness Fairchild supports the Company's historical and projected revenue requirement, rate of return calculation, and related exhibits mandated by the Commission's rate case requirements.
- Jillian Fan – Witness Fan will be sponsoring testimony detailing the relationship between SEMCO and its parent company, AltaGas, as well as describing the parent allocation methodology.
- Walter E. Fitzgerald – Witness Fitzgerald will be sponsoring proposed revisions to the Company's Transportation Services and Customer Choice sections of the Rate Book for Natural Gas Services, Sections E and F, respectively. Witness Fitzgerald will also sponsor rate calculations for the Company's lost-and-unaccounted-for gas, company use gas, uncollectible accounts, and gas in storage.

- Ann L. Forster – Witness Forster will be sponsoring testimony describing the Company's compensation philosophy, including incentive compensation, and supporting why total compensation should be recovered in rates.
- Robert B. Hevert – Witness Hevert is sponsoring the Company's proposed return on equity and supporting its proposed cost of debt and capital structure.
- Matthew C. Kosht – Witness Kosht will be sponsoring testimony detailing SEMCO's commitment to cyber security and the ongoing related enhancements.
- Steven Q. McLean – Witness McLean will be sponsoring testimony supporting the continuation of special transportation contracts for certain extra-large volume transportation customers and the recovery in base rates of the discounts in such contracts. He will also support the calculation of the MRP and IRIP surcharges. In addition, Witness McLean will support the recovery of various incremental expenses.
- Mark A. Moses – Witness Moses is sponsoring testimony detailing the relationship between SEMCO and SEMCO Gas and their shared services. He will support the methodology used in allocating the cost of such shared services. Witness Moses is also sponsoring the methodologies used in forecasting O&M expense, property and other tax expenses, and other gas revenues.
- Laurie K. Owens – Witness Owens will be sponsoring testimony proposing the new low-income credit programs, as well as the elimination of both electronic payment convenience fees and shut-off notice fees. Witness Owens will also sponsor an adjustment associated with the appliance repair program, a value-added program offered by the Company.
- Paul H. Raab – Witness Raab will be sponsoring testimony on the Company's sales and transportation volume forecast and weather normalization. He will also sponsor the Company's cost of service study.

- Katie L. Singer – Witness Singer is sponsoring testimony supporting the Company's projected capital expenditures, including MCP. She will also discuss the Company's proposed extended MRP and new IRIP programs.
- Tracy L. Vincent – Witness Vincent will be sponsoring testimony supporting depreciation rates as approved in Case No. U-18452, amortization amounts related to deferred riser valves and manufactured gas plant costs, allocation methodology among occupants at the recently purchased SEMCO Gas headquarters facilities, and changes to GAAP and the impact on SEMCO Gas's accounting records.

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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF BRUCE H. FAIRCHILD

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

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

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.

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 of Texas ("PUCT"). 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 PUCT, I assisted in managing a division comprised of approximately twenty-five professionals responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems. I testified on behalf of the PUCT staff in numerous cases involving most major investor-owned and cooperative electric, telephone, and water/sewer utilities in the state on 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 involving gas, electric, telephone, and water/sewer service. 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 PUCT.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor exhibits and schedules supporting the rate increase requested by SEMCO Energy Gas Company ("SEMCO Gas") in this proceeding.

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, Inc. from my participation in SEMCO Gas's last four rate cases before the Michigan Public Service Commission ("Commission") (Case Nos. U-13575, U-14338, U-14893, and U-16169) and previous work with SEMCO's Alaskan divisions (collectively "ENSTAR"). In connection with the present filing, I reviewed and relied on a variety of accounting and financial data from the books and records of SEMCO Gas and a number of conversations with management in the course of preparing this filing. These sources, coupled with my experience in the fields of accounting, finance, economics, and utility regulation, enabled me to acquire a working knowledge of SEMCO Gas and formed the basis for my analyses and conclusions.

Q. What time periods serve as the basis for SEMCO Gas's rate filing?

A. The starting point for this filing is SEMCO Gas's actual experience during the historical year ended December 31, 2018. Various adjustments are then made to develop a projected test year based on the twelve months ending December 31, 2020.

I. HISTORICAL YEAR

Q. Please describe the exhibits and schedules presenting data for the historical year ended December 31, 2018.

A. Exhibit A-1 (BHF-1), Schedule A-1 through Exhibit A-4 (BHF-22), Schedule D-5 are the Commission's Standard Exhibits and Schedules for rate case filings and reflect the results of SEMCO Gas's operations for the historical year ended December 31, 2018. All of the information shown in this portion of the SEMCO Gas's filing omits adjustments to normalize data, eliminate non-recurring items, account for known and measurable changes, and, except for interest synchronization, reflect other regulatory conventions. Accordingly, while these exhibits and schedules provide historical "per books" data that serve as the starting point for evaluating existing base rates, SEMCO Gas's requested rates are ultimately based on the data and information contained in subsequent exhibits and schedules using data for the projected test year ending December 31, 2020.

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

A. I am sponsoring all of the exhibits and schedules for the historical year ended December 31, 2018 (*i.e.*, Exhibit A-1 (BHF-1), Schedule A-1 through Exhibit A-4 (BHF-22), Schedule D-5). I prepared these exhibits and schedules using information obtained from SEMCO Gas's books, records, and Commission Annual Reports.

Q. What are the results of the historical year ended December 31, 2018 as reflected in Exhibit A-1 (BHF-1), Schedule A-1 through Exhibit A-4 (BHF-22), Schedule D-5?

A. As shown on Schedule A-1 of Exhibit A-1 (BHF-1), based on the revenues, expenses, and investment for the historical year ended December 31, 2018, SEMCO Gas earned some $7.9 million more than its income requirements. However, the results of the 2018 historical year are not indicative of SEMCO Gas's ongoing operations because they have not been adjusted for normal conditions, do not reflect projected levels of revenues, investment, and operating expenses (particularly the operating and capital costs associated with the completion of the Marquette Connector Pipeline project ("MCP")), and do not incorporate other regulatory conventions necessary to determine prospective base rates for SEMCO Gas.

II. PROJECTED TEST YEAR

Q. Please describe the exhibits and schedules presenting data for the projected test year ending December 31, 2020.

A. SEMCO Gas's results of operations for the projected year ending December 31, 2020 are developed in Exhibit A-11 (BHF-23), Schedule A-1 through Exhibit A-14 (BHF-42), Schedule D-5. These exhibits and schedules incorporate adjustments and projections for the period when rates will become effective and serve as the basis for SEMCO Gas's requested base rates.

Q. Which schedules for the projected test year ending December 31, 2020 are you sponsoring?

A. I am sponsoring the following exhibits and schedules:

Exhibit	Schedule	Title
Exhibit A-11	Schedule A-1 (BHF-23)	Projected Revenue Deficiency
	Schedule A-2 (BHF-24)	Projected Financial Metrics
Exhibit A-12	Schedule B-1 (BHF-25)	Projected Rate Base
	Schedule B-2 (BHF-26)	Projected Utility Plant
	Schedule B-3 (BHF-27)	Projected Accumulated Depreciation
	Schedule B-4 (BHF-28)	Projected Working Capital
Exhibit A-13	Schedule C-1 (BHF-29)	Projected Net Operating Income
	Schedule C-2 (BHF-30)	Projected Revenue Multiplier
	Schedule C-3 (BHF-31	Projected Revenues
	Schedule C-6 (BHF-33)	Projected Depreciation & Amortization
	Schedule C-8 (BHF-33)	Projected Federal Income Taxes
	Schedule C-9 (BHF-34)	Projected State Income Taxes
	Schedule C-10 (BHF-35)	Projected Other Taxes
	Schedule C-11 (BHF-36)	Projected AFUDC
Exhibit A-14	Schedule D-1 (BHF-37)	Projected Overall Rate of Return
	Schedule D-1.1(BHF-38)	Projected Accum. Def. Income Taxes
	Schedule D-2 (BHF-39)	Cost of Long-term Debt
	Schedule D-3 (BHF-40)	Cost of Short-term Debt
	Schedule D-4 (BHF-41)	Cost of Preferred Stock
	Schedule D-5 (BHF-42)	Cost of Common Equity

Q. What are the results of Exhibit A-11 (BHF-23), Schedule A-1 through Exhibit A-14 (BHF-42), Schedule D-5 for the projected test year ending December 31, 2020?

A. As shown on Exhibit A-11 (BHF-23), Schedule A-1, after incorporating the various adjustments described by me and other witnesses to reflect projected revenues, expenses, and investment during the test period ending December 31, 2020 and an overall rate of return of 7.04%, SEMCO Gas's current rates are deficient by $38,114,307. This revenue deficiency is calculated by first comparing SEMCO Gas's income requirements, calculated by multiplying projected 2020 rate base times SEMCO Gas's requested rate of return, with its adjusted 2020 net operating income under current rates, and then grossing up the income deficiency by a revenue conversion multiplier (Exhibit A-13 (BHF-32), Schedule C-2). The resulting preliminary revenue deficiency is then reduced by the amortization of excess accumulated deferred income taxes ("ADIT") ordered in Case No. U-20311 to calculate SEMCo Gas's net requested increase in base rates.

A. Exhibit A-12

Q. What is the purpose of Exhibit A-12?

A. Exhibit A-12 develops SEMCO Gas's projected 2020 rate base, with Schedules B-1, B-2, B-3, and B-4 summarizing 2020 total rate base, 2020 utility plant, 2020 accumulated depreciation, and 2020 working capital, respectively. Schedule B-5 of Exhibit A-12 (KLS-1) contains the details of SEMCO Gas's capital expenditures for 2018-2020 and is sponsored by Witness Katie Singer.

Q. Please describe how projected 2020 utility plant in service is determined.

A. As shown at the bottom of Exhibit A-12 (BHF-26), Schedule B-2, projected 2020 utility plant is calculated as the average of projected year-end 2019 and 2020 utility plant, adjusted to add approximately $5 million so that main replacement expenditures are measured at year-end 2020. Beginning with the 13-month average 2018 utility plant from Exhibit A-2 (BHF-4), Schedule B-2, the first step is to move average 2018 plant forward to the 2018 year-end plant balance. Next, 2018 year-end construction work in progress ("CWIP") that will be placed in service during 2019 and the 2019 capital additions described by Ms. Singer are added and 2019 plant retirements removed, resulting in a 2019 year-end plant balance of $1,018,982,191. A similar process is followed to calculate 2020 year-end utility plant, with 2020 capital expenditures being added and 2020 retirements being subtracted from the 2019 year-end plant balance. The resulting 2020 year-end plant balance of $1,061,966,852 is then averaged with the 2019 year-end plant balance to calculate average 2020 utility plant of $1,040,474,521. For the reasons explained in the testimony of Witness Steven McLean, $5,028,500 in 2020 main replacement expenditures are added to the average 2020 plant balance to produce projected 2020 utility plant of $1,045,503,022.

Q. How is projected 2020 accumulated depreciation determined?

A. Projected 2020 accumulated depreciation is developed on Exhibit A-12 (BHF-27), Schedule B-3 and, like utility plant, is calculated as the average of the 2019 and 2020 year-end accumulated depreciation balances. The 13-month average 2018 accumulated depreciation from Exhibit A-2 (BHF-5), Schedule B-3 serves as the starting point. After moving average 2018 accumulated depreciation and amortization to 2018 year-end, 2019 depreciation and amortization expenses are added and 2019 plant retirements are removed to arrive at 2019 year-end accumulated depreciation of $357,670,093. This 2019 year-end balance is then rolled forward to year-end 2020 by adding 2020 depreciation and amortization expenses and subtracting 2020 plant retirements. Averaging the resulting 2020 year-end accumulated depreciation of $384,182,864 with the 2019 year-end balance produces projected 2020 average accumulated depreciation and amortization of $370,926,479.

Q. How is projected 2020 working capital determined?

A. SEMCO Gas's projected 2020 working capital requirements are based on those developed in Exhibit A-2, Schedule B-4 (BHF-6) for the historical year ended December 31, 2018, adjusted for the projected increase in the level of investment in gas stored underground. As described in the testimony of Witness Walter Fitzgerald, the projected average balance of gas stored underground during 2020 is $29,452,372, which results in SEMCO Gas's projected 2020 working capital requirements being $49,960,181, as shown at the bottom of Exhibit A-12 (BHF-6), Schedule B-4.

Q. What, then, is SEMCO Gas's projected 2020 rate base?

A. As summarized on Exhibit A-12 (BHF-25), Schedule B-1, reducing projected 2020 utility plant from Exhibit A-12 (BHF-26), Schedule B-2 of $1,045,503,022 (which consists of plant in service $1,045,351,299 and plant held for future use of $151,723) by projected 2020 accumulated depreciation and amortization of $370,926,479 from Exhibit A-12 (BHF-27), Schedule B-3 results in 2020 projected net utility plant of $674,576,543. Adding to this amount projected 2020 working capital of $49,960,181 from Exhibit A-12 (BHF-28), Schedule B-4 produces SEMCO Gas's projected 2020 rate base of $724,536,724.

B. <u>Exhibit A-13</u>

Q. What is the purpose of Exhibit A-13?

A. Exhibit A-13 develops SEMCO Gas's projected 2020 net operating income under current rates. As described earlier, this projected 2020 net operating income is then compared on Exhibit A-11 (BHF-23), Schedule A-1 with SEMCO Gas's required income (computed as the projected 2020 rate base times its requested rate of return) to determine SEMCO Gas's income and, in turn, its revenue deficiency.

Q. Please describe Exhibit A-13 (BHF-29), Schedule C-1.

A. Exhibit A-13 (BHF-29), Schedule C-1 is the summary schedule that combines projected 2020 revenues and expenses under current rates to calculate projected 2020 adjusted net operating income. The details underlying the revenues and expenses shown on Exhibit A-13 (BHF-29), Schedule C-1 are contained in Exhibit A-13, Schedules C-1 through C-11.

Q. What is shown on Exhibit A-13 (BHF-31), Schedule C-3?

A. Exhibit A-13 (BHF-31), Schedule C-3 develops projected 2020 revenues at current rates, broken down between sales revenues, transportation revenues, and other gas revenues. Projected 2020 sales and transportation revenues are developed by Witness Dennis on Exhibit A-16 (JLD-1), Schedule F-2, with Witness Mark Moses sponsoring the development of other gas revenues on Exhibit A-13 (MAM-1), Schedule 3.1.

Q. Please describe Exhibit A-13 (BHF-32), Schedule C-4.

A. The purpose of Exhibit A-13 (BHF-32), Schedule C-4 is to separate SEMCO Gas's cost of gas sold into two amounts: 1) those included in operations and maintenance expenses, and 2) those recovered through the gas cost recovery ("GCR") process. First, as shown in the upper portion of Exhibit A-13 (BHF-32), Schedule C-4, the historical 2018 cost of gas sold from Exhibit A-3 (BHF-10), Schedule C-4 is adjusted to remove $262, 793 in expenses associated with the operation of gas measuring stations, which are included in operations and maintenance expenses. The resulting adjusted 2018 cost of gas sold is then reduced to reflect the projected 2020 cost of gas included in the GCR of $154,955,961. Witness McLean sponsors the development of projected 2020 LAUF and company-use gas of $535,434 on pages 1 and 2 of Exhibit A-13 (SQM-2), Schedule C-4.1.

Q. What is shown on Exhibit A-13 (BHF-32), Schedule C-6?

A. Exhibit A-13 (BHF-32), Schedule C-6 develops projected 2020 depreciation and amortization expense. Beginning with historical 2018 depreciation and amortization expenses from Exhibit A-3 (BHF-12), Schedule C-6, depreciation expense on utility plant in 2018 is removed and replaced with projected 2020 depreciation expense on projected 2020 utility plant. Next, a similar adjustment is made to replace the 2018 amortization of capitalized manufactured gas plant ("MGP") clean-up costs, which are discussed in the testimony of Witness Tracy Vincent, with 2020 MGP amortization expense. Finally, an adjustment is made to include the amortization of the cost of service valve replacements, which are also discussed by Witness Vincent, over three years. As shown at the bottom of Exhibit A-13 (BHF-32), Schedule C-6, this series of calculations results in projected 2020 depreciation and amortization expenses totaling $33,718,222.

Q. Please describe Schedules C-7 and C-10 of Exhibit A-13.

A. All of SEMCO Gas's projected 2020 taxes other than income are shown on Exhibit A-13 (MAM-3), Schedule C-7. Witness Moses describes the adjustments to roll historical 2018 taxes other than income forward to 2020 and include additional property taxes attributable to the MCP, and Witness McLean sponsors an adjustment to include property taxes assessed SEMCO Gas by the state of Kansas. As shown Exhibit A-13 (MAM-3), Schedule C-7, projected 2020 taxes other than income total $16,354,703.

Q. Please describe Exhibit A-13 (BHF-33), Schedule C-8?

A. Exhibit A-13 (BHF-33), Schedule C-8 develops projected 2020 federal income taxes under SEMCO Gas's current rates. The federal corporate income tax rate of 21% is applied to federal taxable income calculated as projected 2020 revenues (Exhibit A-13 (BHF-31), Schedule C-3) less projected 2020 operating expenses (Exhibit A-13, Schedules C-4 through C-7), projected 2020 state income taxes ((Exhibit A-13 (BHF-34), Schedule C-9), and allowable (*i.e.*, synchronized) interest expense (*i.e.*, projected 2020 rate base times the projected 2020 weighted cost of debt), plus permanent book-tax timing differences and the equity portion of allowance for funds used during construction ("AFUDC") included in SEMCO Gas's book depreciation expense. As shown at the bottom of Exhibit A-13, Schedule C-8, projected 2020 federal income taxes under SEMCo Gas's current rates total $2,485,688.

Q. What is shown on Schedule C-9 of Exhibit A-13 (BHF-34)?

A. Exhibit A-13 (BHF-34), Schedule C-9 develops projected 2020 state income taxes. The Michigan corporate income tax rate of 6% is applied to state taxable income, which is calculated as described above for federal taxable income, except for the deduction for state income taxes. This results in state income taxes under SEMCO Gas's current rates of $755,522.

Q. Please describe Exhibit A-13 (BHF-36), Schedule C-11?

A. During 2018 and 2019, SEMCO Gas recorded AFUDC in connection with the construction of the MCP. Because this project is complete and in service, no AFUDC is projected to be accrued in 2020, so the AFUDC capitalized during the historical year 2018 is eliminated.

Q. What is the end-result of the various calculations shown on Schedules C-3 through C-11 of Exhibit A-13 (BHF-36) described above?

A. The projected 2020 revenues from Exhibit A-13 (BHF-31), Schedule C-3 and projected 2020 operating expenses from Exhibit A-13, Schedules C-4 through C-11 are summarized on Exhibit A-13 (BHF-29), Schedule C-1. Because state and federal income taxes are calculated using allowable interest expense, an adjustment for interest synchronization is not required. As shown there, SEMCO Gas's projected 2020 adjusted net operating income at current rates is $20,743,616. As indicated earlier, this amount is carried to Exhibit A-11 (BHF-23), Schedule A-1 were it is used to calculate SEMCO Gas's revenue deficiency.

C. Exhibit A-14

Q. What is the purpose of Exhibit A-14?

A. Exhibit A-14 develops the 7.04% rate of return SEMCO Gas requests be applied to projected 2020 rate base. As reflected on Exhibit A-14 (BHF-37), Schedule D-1, this rate of return is based on capital ratios of 33.01% debt, 51.70% common equity, and 15.29% ADIT, to which an average cost of debt of 4.89%, a rate of return on equity ("ROE") of 10.50%, and a zero cost of ADIT are applied, respectively. I sponsor the amounts included in the capital structure and the cost of debt, with Witness Robert Hevert addressing the investor-supplied capital structure ratios and ROE.

Q. Please describe the amounts comprising the capital structure shown in column (b) on Exhibit A-14 (BHF-37), Schedule D-1.

A. The projected 2020 13-month average capital structure of $724,536,724 is equal to the 2020 rate base from Exhibit A-12 (BHF-25), Schedule B-1. From this total, projected 2020 ADIT are subtracted, with the remaining investor-supplied capital being apportioned between debt and equity using the respective 38.97% and 61.03% ratios for the historical year ended December 31, 2018 from Exhibit A-4 (BHF-18), Schedule D-1.

Q. Why are there two ADIT balances on Exhibit A-14 (BHF-37), Schedule D-1?

A. The Tax Cut and Jobs Act ("TCJA") that became effective January 1, 2018 lowered the federal corporate income tax rate from 35% to 21%, which reduced

SEMCO Gas's expected future tax liability and, in turn, it's ADIT. As allowed by the TCJA for utilities, the difference between ADIT at tax rates of 35% and 21% was recorded as a regulatory liability to be amortized over appropriate periods. Accordingly, the ADIT shown in Exhibit A-14 (BHF-37), Schedule D-1 consists of two balances. The first is labeled "regular" and is the ADIT recorded on SEMCO Gas's books following TCJA, with the balance labeled "excess" being the regulatory liability, which is being amortized as prescribed in Case No. U-20311.

Q. What is the amount of projected 2020 "regular" ADIT?

A. The amount of projected 2020 regular ADIT is developed in column (c) on Exhibit A-14 (BHF-38), Schedule D-1.1 and is calculated as the average of the projected 2019 and 2020 year-end regular ADIT balances. The 13-month average 2018 regular ADIT from Exhibit A-4, Schedule D-1 serves as the starting point, which is moved forward to year-end 2018. Adjustments are then made to reflect projected 2019 and 2020 year-end regular ADIT balances of $60,835,094 and $62,562,735, respectively, which are then averaged to produce projected 2020 regular ADIT of $61,698,915.

Q. What is the amount of projected 2020 "excess" ADIT?

A. Projected 2020 excess ADIT is developed in column (d) on Exhibit A-14 (BHF-38), Schedule D-1.1. Again using the 13-month average 2018 excess ADIT from Exhibit A-4 (BHF-20), Schedule D-1 as the starting point, the regulatory liability is moved forward to reflect the year-end balance, which is then amortized in 2019 and 2020 as provided for in Case No. U-20311. Averaging the projected 2019 and 2020 year-end respective excess ADIT balances of $50,041,313 and $48,132,755 produces projected 2020 excess ADIT of $49,087,034.

Q. What is the cost of debt included in SEMCO Gas's requested rate of return?

A. As developed on Exhibit A-14 (BHF-39), Schedule D-2, SEMCO Gas's projected 2020 cost of debt is 4.89%. This cost is based on the debt issues outstanding during the historical year ended December 31, 2018 from Exhibit A-4 (BHF-19), Schedule D-2, adjusted for the amortization of debt expense in 2019 and 2020, as shown in footnote (a).

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

A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap2@texas.net

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.

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, 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

"Federal Energy Regulatory Commission Audits of Common Carriers (Procedures for Audit Compliance)", Energy Transfer Accounting Employee Education, Dallas and Houston, Texas (December 2018).

"Perspectives on Texas Utility Regulation", TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).

"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).

APPENDIX 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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
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 Requirements
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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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
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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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
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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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
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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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
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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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 – Energas	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 RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG-280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
162.	ETC Katy Pipeline, Ltd.	Texas RRC	9841	Dec-08	Revenue Requirements
163.	Oklahoma Natural Gas	Oklahoma CC	200800348	Jan-09	Rate of Return on Equity
164.	Entergy Mississippi, Inc.	Mississippi PSC	EC-123-0082	Mar 09	Rate of Return on Equity
165.	ENSTAR Natural Gas Company	Alaska RCA	U-09-69 U-09-70	Jun-09 Jul-09 Oct-09	Revenue Requirements, Cost Allocation, and Rate Design
166.	EasTrans, LLC	Texas RRC	9857	Jun-09	Rate of Return
167.	Oklahoma Natural Gas	Oklahoma CC	200900110	Jun-09	Rate of Return
168.	Crosstex CCNG Transmission Ltd.	Texas RRC	9858	Jun-09	Revenue Requirements
169.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul-09	Rate of Return
170.	ENSTAR Natural Gas Company	Alaska RCA	U-08-142	Jul-09	Gas Cost Adjustment
171.	Kinder Morgan Texas Pipeline, LLC	Texas RRC	9889	Jul-09	Rate of Return
172.	Koch Alaska Pipeline Company	Alaska RCA	TL 133-308	Aug-09	Rate of Return
173.	ExxonMobil Pipeline Co.	Alaska RCA	TL-147-304	Nov-09	Rate of Return
174.	Texas Gas Service Company	El Paso PURB	--	Dec-09	Rate of Return
175.	Unocal Pipeline Company	Alaska RCA	TL126-312	Dec-09	Rate of Return
176.	Kuparuk Transportation Company	Alaska RCA	P-08-05	Apr-10	Rate of Return
177.	Trans-Alaska Pipeline System	FERC	ISO9-348-000	Apr 10 Oct 10	Rate of Return
178.	Texas Gas Service	Texas RRC	9988	May 10 Aug 10	Rate of Return
179.	SEMCO Energy Gas Company	Michigan PSC	U-16169	Jun 10 Dec 10	Revenue Requirements
180.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul 10	Rate of Return
181.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-308	Aug 10	Rate of Return
182.	CPS Energy	Texas PUC	36633	Sep 10 Apr 11	Rate of Return for MOU
183.	ExxonMobil Pipeline Co.	Alaska RCA	TL-151-304	Dec 10	Rate of Return
184.	Unocal Pipeline Company	Alaska RCA	TL132-312	Feb 11	Rate of Return
185.	New Mexico Gas Company	NM PRC	11-00042-UT	Mar 11	Rate of Return
186.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-143-301	May 11	Rate of Return

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	Enstar Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	Enstar Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	P-18-0__	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-___	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	Case No. U-20479
for authority to increase its rates for the	)	
distribution and transportation natural gas	)	
and other related relief.	)	

DIRECT TESTIMONY OF ROBERT B. HEVERT
ON BEHALF OF
SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Robert B. Hevert
On Behalf of
SEMCO Energy Gas Company

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS 1

II. PURPOSE AND OVERVIEW OF TESTIMONY 3

III. SUMMARY OF ISSUES SURROUNDING COST OF EQUITY ESTIMATION IN REGULATORY PROCEEDINGS 9

IV. COST OF EQUITY ESTIMATION 16

A. Proxy Group Selection 17

B. Cost of Equity Estimation 20

V. BUSINESS RISKS AND OTHER CONSIDERATIONS 27

A. Small Size 27

B. Capital Expenditures 31

VI. CAPITAL MARKET ENVIRONMENT 35

VII. CAPITAL STRUCTURE 43

VIII. CONCLUSIONS AND RECOMMENDATION 48

IX. APPENDIX A 50

A. Constant Growth Discounted Cash Flow Model 50

B. CAPM Analysis and Empirical CAPM Analysis 57

C. Bond Yield Plus Risk Premium Approach 66

D. Expected Earnings Analysis 69

GLOSSARY OF FREQUENTLY USED TERMS

TERM	DESCRIPTION
Beta Coefficient	A component of the CAPM that measures the risk of a given stock relative to the risk of the overall market.
Bond Yield Plus Risk Premium Approach	A risk premium model used to estimate the Cost of Equity. The Bond Yield Plus Risk Premium approach assumes that investors required a risk premium over the cost of debt as compensation for assuming the greater risk of common equity investment. The model is expressed as a bond yield plus equity risk premium.
Capital Asset Pricing Model (“CAPM”)	A risk premium-based model used to estimate the Cost of Equity, assuming the stock is added to a well-diversified portfolio. The CAPM assumes that investors are compensated for the time value of money (represented by the Risk-Free Rate), and risk (represented by the combination of the Beta Coefficient and the Market Risk Premium).
Capital Structure	The capital structure is how a utility finances its overall investments and expenses by using various sources of funds. Capital Structure generally comprises of debt (short-term and long-term) and equity (common and preferred).
Constant Growth DCF Model	A form of the DCF model that assumes cash flows will grow at a constant rate, in perpetuity. The model simplifies to a form that expresses the Cost of Equity as the sum of the expected dividend yield and the expected growth rate.
Cost of Equity	The return required by investors to invest in equity securities. The terms “Return on Equity” and “Cost of Equity” are used interchangeably.
Discounted Cash Flow (“DCF”) Model	A model used to estimate the Cost of Equity based on expected cash flows. The Cost of Equity equals the discount rate that sets the current market price equal to the present value of expected cash flows.
Dividend Yield	For a given stock, the current annualized dividend divided by its current market price.
Empirical Capital Asset Pricing Model (“ECAPM”)	Empirical CAPM is a variant of the CAPM model. ECAPM adjusts for the CAPM’s tendency to under-estimate returns for companies that have

TERM	DESCRIPTION
	Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks
Expected Earnings Approach	The Expected Earnings analysis is based on the principle of opportunity costs and compares returns on book equity to ROEs, investors are able to directly compare returns from investments of similar risk.
Gross Domestic Product ("GDP")	The value of all finished goods and services produced within a country during a given period of time (usually measured annually). GDP includes public and private consumption, government expenditures, investments, and net exports (that is, exports minus imports).
Market Return	The expected return on the equity market, taken as a portfolio.
Market Risk Premium	The additional compensation required by investing in the equity market as a portfolio over the Risk-Free rate. The Market Risk Premium is a component of the CAPM.
Proxy Group	A group of publicly traded companies used as the "proxy" for the subject company (in this case, SEMCO). Proxy companies are sometimes referred to as "Comparable Companies."
Quantitative Easing	Quantitative Easing is a monetary policy in which the central bank purchases government securities or other securities from the market to increase the money supply and encourage lending and investment.
Return on Equity ("ROE")	The return required by investors to invest in equity securities. The terms "Return on Equity" and "Cost of Equity" are used interchangeably. Please note that the ROE in this context is distinct from the accounting measure sometimes referred to as the "Return on Average Common Equity".
Risk-Free Rate	The rate of return on an asset with no risk of default.
Risk Premium	The additional compensation required by investors for taking on additional increments of risk. Risk Premium-based approaches are used in addition to the DCF and CAPM to estimate the Cost of Equity.

TERM	DESCRIPTION
Treasury Yield	The return on Treasury securities; the yield on long-term Treasury bonds is considered to be a measure of the Risk-Free Rate.

DIRECT TESTIMONY

OF

ROBERT B. HEVERT

Case No. U-20479

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, affiliation, and business address.

A. My name is Robert B. Hevert. I am a Partner at ScottMadden, Inc. ("ScottMadden") and my business address is 1900 West Park Drive, Suite 250, Westborough, MA 01581.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony on behalf of SEMCO Energy Gas Company ("SEMCO Gas" or the "Company").

Q. Please identify the exhibits which you are sponsoring in this case.

A. I sponsor the following exhibits:

Exhibit A-53 (RBH-1) – Constant Growth Discounted Cash Flow Model
Exhibit A-54 (RBH-2) – Retention Growth Estimate
Exhibit A-55 (RBH-3) – Ex-Ante Market Risk Premium
Exhibit A-56 (RBH-4) – Calculated Beta Coefficients
Exhibit A-57 (RBH-5) – Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Exhibit A-58 (RBH-6) – Bond Yield Plus Risk Premium
Exhibit A-59 (RBH-7) – Expected Earnings Analysis
Exhibit A-60 (RBH-8) – Small Size Premium
Exhibit A-61 (RBH-9) – Proxy Group Capital Structure

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

A. Yes.

Q. Please describe your educational background.

A. I hold a Bachelor's degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q. Please describe your experience in the energy and utility industries.

A. I have worked in regulated industries for over thirty years, having served as an executive and manager with consulting firms, a financial officer of a publicly traded natural gas utility, and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in more than 250 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies, the Federal Energy Regulatory Commission ("FERC"), the Alberta Utilities Commission, and United States Federal Court. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included as Attachment A here

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present evidence and provide a recommendation regarding the Company's Return on Equity ("ROE").[1] Additionally, I assess the reasonableness of the Company's proposed capital structure. My analyses and conclusions are supported by the data presented in Exhibits A-53 (RBH-1) through A-61 (RBH-9), which have been prepared by me or under my direction.

Q. What are your conclusions regarding the appropriate Cost of Equity and capital structure for the Company?

A. My analyses indicate that in today's capital markets, an ROE in the range of 10.00 percent to 10.75 percent represents the range of equity investors' required return for investment in a natural gas utility such as SEMCO Gas. Based on the quantitative and qualitative analyses as discussed therein, including the risk profile of the Company, it is my view that 10.50 percent is a reasonable and appropriate estimate of the Company's Cost of Equity.

As to its proposed capital structure for the test year ending December 31, 2020, which includes 61.03 percent common equity and 38.97 percent long-term debt, I conclude that the Company's proposal is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. Given the consistency of its proposal with similarly

1 Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

situated utility companies, I conclude that the Company's proposed capital structure is reasonable and appropriate.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore relied on three widely-accepted approaches to develop my ROE recommendation: (i) the Constant Growth Discounted Cash Flow ("DCF") model; (ii) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (iii) the Bond Yield Plus Risk Premium approach. That range is corroborated by the Expected Earnings approach which, as I discuss later in my Direct Testimony, is supported by recent FERC Orders.

In addition to the methodologies noted above, my estimate also takes into consideration: (i) the Company's relatively small size compared to the proxy group and (ii) the Company's planned capital expenditures. I also considered the changing capital market and business conditions, including changes in Federal monetary policy. Although I did not make any explicit adjustments to my ROE estimates for those factors, I did take them into consideration in determining where the Company's Cost of Equity falls within the range of analytical results.

Q. What are the key factors considered in your analyses and upon which you base your recommended ROE?

A. My analyses and recommendations consider the following key factors:

- The *Hope* and *Bluefield* (as referenced and defined below) decisions that established the standards for determining a fair and reasonable allowed return on equity, including: (i) consistency of the allowed return with other businesses having similar risk; (ii) adequacy of the return to provide access to capital and support credit quality; and (iii) confidence that the end result leads to just and reasonable rates.
- The effect of the current capital market conditions on investors' return requirements.
- The Company's business risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

As discussed in Section VI, I considered the results of those methods in the context of general capital market factors. Based on those analyses, I conclude that a range of 10.00 percent to 10.75 percent represents reasonable estimates of the Company's ROE.

Q. How is the remainder of your Direct Testimony organized?

A. The balance of my Direct Testimony is organized as follows:

Section III – Provides a summary of issues regarding Cost of Equity estimation in regulatory proceedings and discusses the regulatory guidelines pertinent to the development of the cost of capital;

Section IV – Discusses the Cost of Equity analyses;

Section V – Provides a discussion on specific risk factors and other considerations that have a direct bearing on SEMCO's Cost of Equity;

Section VI – Highlights the current capital market conditions and their effect on the Company's Cost of Equity;

Section VII – Provides my analysis of the SEMCO's capital structure;

Section VIII – Summarizes my conclusions and recommendations; and

Section IX – Appendix A provides the technical details of my analytical approaches.

Q. What are the results of your analyses?

A. The results of my analyses are summarized in Table 1 through Table 3 (see also, Exhibit A-53 (RBH-1), Exhibit A-57 (RBH-5), and Exhibit A-58 (RBH-8)) below.

Table 1: Summary of Constant Growth DCF Results

	Mean	Mean High
30-Day Average	9.64%	13.53%
90-Day Average	9.68%	13.57%
180-Day Average	9.68%	13.57%

Table 2: Summary of CAPM Results

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	9.13%	10.92%
Near Term Projected 30-Year Treasury (3.25%)	9.35%	11.13%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.32%	12.46%
Near Term Projected 30-Year Treasury (3.25%)	10.54%	12.68%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.26%	12.37%
Near Term Projected 30-Year Treasury (3.25%)	10.47%	12.59%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	11.15%	13.53%
Near Term Projected 30-Year Treasury (3.25%)	11.37%	13.75%

Table 3: Summary of Bond Yield Plus Risk Premium Results

Bond Yield Plus Risk Premium Approach	
Current 30-Year Treasury (3.03%)	9.89%
Near Term Projected 30-Year Treasury (3.25%)	9.91%
Long Term Projected 30-Year Treasury (4.05%)	10.11%

As shown in Tables 1 through 3, I performed several analyses to estimate the Company's Cost of Equity. Those results are supported by the results of my Expected Earnings analysis, which range from 9.58 percent to 12.13 percent, with an average of 10.73 percent.[2] Based on those analytical results, and in light of the considerations discussed throughout the balance of this testimony, I believe a reasonable range is from 10.00 percent to 10.75 percent and, within that range, an ROE of 10.50 percent is reasonable.

Q. Are there other factors that should be considered in determining the weight given to the methods and results summarized above?

A. Yes. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more, or less, relevant as market conditions and data change. Important considerations are the consistency of each model's underlying assumptions with current and expected market conditions, and the reasonableness of its results relative to observable benchmarks.

Risk Premium-based methods (such as the CAPM) provide a measure of risk and directly reflect investors' expectations regarding future market returns. Other Risk Premium approaches (such as the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lock-step with interest rates. For example, at times interest rates fall because investors can be so risk averse that they would rather accept a very

2 Exhibit A-59 (RBH-7).

modest return on Treasury securities than take on the risk of equity ownership. In such circumstances, low interest rates suggest an increasing, not a decreasing, Cost of Equity. Therefore, the important analytical issue is understanding each model's fundamental structure and assumptions, and considering its results in the context of current and expected market conditions.

As discussed in Section III, below, the ROE should be comparable to returns investors expect to earn on other investments of similar risk. To that point, the mean low results of my Constant Growth DCF model are below any authorized ROE for a natural gas utility since at least 1980 and nearly 300 basis points below SEMCO Gas's currently authorized ROE.[3]

With those considerations in mind, I believe my recommendation reasonably reflects investors' return requirements in the current market environment.

III. SUMMARY OF ISSUES SURROUNDING COST OF EQUITY ESTIMATION IN REGULATORY PROCEEDINGS

Q. Before addressing the specific aspects of this proceeding, please provide a general overview of the issues surrounding the Cost of Equity in regulatory proceedings.

A. In general terms, the Cost of Equity is the return investors require to make an equity investment in a firm. That is, investors will only provide funds to a firm if the

3 Source: S&P Global Market Intelligence Regulatory Research Associates.

return they *expect* is equal to, or greater than, the return they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity"; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For an investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable investment opportunities. If it is not, investors will sell the "over-valued" security, and buy the "under-valued" security until the expected returns on the two are aligned.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[4] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear that additional "residual risk," they require higher returns than debt holders. In that basic sense,

4 The observed interest rate may be adjusted to reflect issuance or other directly observable costs.

equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models. As discussed throughout my testimony, each model is subject to its own set of assumptions, which may become more, or less, applicable as market conditions change. In addition, because the Cost of Equity is an opportunity cost, the models typically are applied to a group of “comparable” or “proxy” companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of model results all require the application of reasoned judgment. That judgment should consider data and information, both quantitative and qualitative, not necessarily included in the models themselves.

In the end, the estimated Cost of Equity should reflect the return that investors require in light of relevant risks, and the returns available on comparable investments. A given utility stock may require a higher return based on the risks to which it is exposed relative to other utilities. That is, although utilities may be viewed as a “sector”, that does not mean that all utilities require the same return. The assessment of relative risk and its effect on the Cost of Equity requires the application of reasoned, experienced judgment applied to a variety of data, much of which is qualitative in nature.

Q. Please now provide a brief summary of the regulatory guidelines established for the purpose of determining the ROE.

A. The United States Supreme Court (the "Court") established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) *("Bluefield")*; and (2) *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) *("Hope")*. In those cases, the Court recognized that the fair rate of return on common equity should be: (i) comparable to returns investors expect to earn on other investments of similar risk; (ii) sufficient to assure confidence in the company's financial integrity; and (iii) adequate to maintain and support the company's credit and to attract capital.

Q. Does Michigan precedent provide similar guidance?

A. Yes. In a recent order, the Michigan Public Service Commission ("Commission') stated (as it has in previous rate orders) that it applied the principles set out in *Hope* and *Bluefield* in establishing a fair rate of return.[5] The Commission held:

> The criteria for establishing a fair rate of return for public utilities is rooted in the language of the landmark United States Supreme Court cases *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair rate of return, consideration should be given to both investors and customers. The rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise.[6]

5 *In re Application of DTE Gas Company*, Case No. U-18999, Order at 45 (MPSC Sep. 28, 2017).
6 *Id.*

Citing the Michigan Supreme Court, the Commission concluded:

> Nevertheless, the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use."[7]

Based on those standards, the authorized ROE should provide the Company with the opportunity to earn a fair and reasonable return, and should enable efficient access to external capital under a variety of market conditions.

Q. Why is it important for a utility to be allowed the opportunity to earn a return adequate to attract equity capital at reasonable terms?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide SEMCO Gas with the opportunity to earn a return on equity that is: (i) adequate to attract capital at reasonable terms; (ii) sufficient to ensure its financial integrity; and (iii) commensurate with returns on investments in enterprises having corresponding risks. To the extent SEMCO Gas is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to

7 *Id.* (quoting *Twp. Of Meridian v City of E. Lansing*, 342 Mich 734, 749 (1955)).

attract capital at reasonable terms enables the Company to provide safe, reliable natural gas utility service while maintaining its financial integrity.

Q. How is the Cost of Equity estimated in regulatory proceedings?

A. As noted earlier (and as discussed in more detail later in my testimony), the Cost of Equity is estimated by the use of various financial models. By their nature, those models produce a range of results from which the ROE is estimated. That estimate must be based on a comprehensive review of relevant data and information, and does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the ROE is to ensure the overall analysis reasonably reflects investors' views of the financial markets in general, and of the subject company (in the context of the proxy companies) in particular.

The use of multiple methods, and the consideration given to them, recently was addressed by the FERC. In its November 15, 2018 *Order Directing Briefs,* FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE".[8] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[9] As FERC explained, because the Cost of Equity depends on what the market expects, it is

8 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

9 Docket No. EL11-66-001, *et al.*, *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

important to understand "how investors analyze and compare their investment opportunities."[10] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[11] Those methods include the CAPM, the Risk Premium method, and the Expected Earnings method, all of which I have applied in this proceeding.

The use of multiple models makes intuitive sense when we consider that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. We cannot assume a single method is the best measure of the factors motivating those decisions for all investors, at all times. Intuition suggests it is more appropriate to use as many methods as we reasonably can, and to reflect the many factors motivating investment decisions as best we can. In this instance, intuition, financial theory,[12] and financial practice reach a common conclusion: we

10 *Id*., at para. 33.

11 *Id*., at para. 35. *See*, generally, Docket No. PL19-4-000, *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, March 21, 2019.

12 As Professor Eugene Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the Cost of Equity]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

should apply and reasonably consider multiple methods when estimating the Cost of Equity.

Practitioners and academics recognize that financial models simply are approximations of investor behavior, not precise quantifications of it. They appreciate that models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at ROE determinations. A reasonable ROE estimate, therefore, appropriately considers alternative methods and the reasonableness of their individual and collective results in the context of observable, relevant market information.

IV. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. Regulated utilities primarily use common stock and long-term debt to finance their capital investments. The overall rate of return ("ROR") weighs the costs of the individual sources of capital by their respective book values. While the cost of debt can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

A. Proxy Group Selection

Q. As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for the Company?

A. Because the ROE is market-based, and given that SEMCO Gas is not a publicly traded entity, it is necessary to establish a group of comparable, publicly traded companies to serve as its "proxy." Even if the Company were publicly traded, it is possible that transitory events could bias its market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Please provide a summary profile of SEMCO Gas.

A. SEMCO Gas is a division of SEMCO Energy, Inc.[13] and provides natural gas distribution service to approximately 306,000 customers throughout Michigan.[14] AltaGas's and SEMCO Gas's current long-term issuer credit ratings are as follows:

Table 4: Current Credit Ratings[15]

	S&P	Moody's
AltaGas	BBB- (outlook: Negative)	N/A
SEMCO Gas	BBB- (outlook: Negative)	Baa1 (outlook: Stable)

13 SEMCO Energy, Inc. is a subsidiary of AltaGas Ltd. ("AltaGas").
14 SEMCO Energy Gas Company, MPSC Form P-522, Annual Report of Natural Gas Companies (December 31, 2018), at 123.1.
15 Source: S&P Global Market Intelligence.

Q. How did you select the companies included in your proxy group?

A. I began with the universe of companies that Value Line classifies as Natural Gas Utilities, which includes 11 domestic U.S. utilities, and applied the following screening criteria:

- Because certain of the models used in my analyses assume earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends;
- To ensure the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group have been covered by at least two utility industry equity analysts;
- All the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- To incorporate companies that are primarily regulated gas distribution utilities, I included companies with at least 60.00 percent of operating income derived from regulated natural gas utility operations; and
- I eliminated companies currently known to be party to a merger, or other significant transaction.

Q. Did you include AltaGas in your proxy group?

A. No. To avoid the circular logic that would otherwise occur, it has been my consistent practice to exclude the subject company (or its parent) from the proxy group. Additionally, AltaGas is not included in universe of companies that Value Line classifies as Natural Gas Utilities.

Q. What companies met those screening criteria?

A. The criteria discussed above resulted in a proxy group of the following eight companies:

Table 5: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[16]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

Q. Do you believe that a proxy group of eight companies is sufficiently large?

A. Yes. Because all analysts use some form of screening process to develop proxy groups, those groups, by definition, are not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the range of results derived from a larger, but potentially less comparable proxy group simply by virtue of the larger number of observations. Moreover, because I am using market-based data, my analytical results will not necessarily be tightly clustered around a central point. Results that may be somewhat dispersed do not suggest the screening approach is inappropriate or the results less meaningful. Including companies whose fundamental comparability to the subject company is tenuous, simply for the purpose of expanding the number of observations, does not add relevant information to the analysis.

16 Even though Chesapeake Utilities Corp. is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group. CPK also has an National Association of Insurance Commissioners (NAIC) rating of "NAIC I," which is equivalent to ratings in the "A" category for both Moody's and Standard & Poor's. *See*, Chesapeake Utilities Corporation, 2018 AGA Financial Forum, May 2018, at 28; National Association of Insurance Commissioners, CRP Credit Rating Equivalent to SVO Designations, November 2017.

B. Cost of Equity Estimation

Q. How have you determined the investor-required ROE?

A. As noted earlier, because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. Although several empirical models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity as detailed in Appendix A.[17] When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches.

As a practical matter, no individual model is more reliable than all others under all market conditions. Therefore, it is important to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. As noted earlier, the use of multiple methods, and the consideration given to them, recently was addressed by FERC.

Consistent with that approach, I have considered the results of the Constant Growth DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach. I also have provided an Expected Earnings analysis, which I have applied as a corroborating method. FERC issued similar

---

17 *See*, *e.g.*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed., 2000, at 214.

guidance, using the Expected Earnings analysis in its determination of the "zone of reasonableness", observing that "*investors use those models*".[18]

Q. Please briefly describe the Constant Growth DCF model.

A. The Constant Growth DCF approach defines the Cost of Equity as the sum of (i) the expected dividend yield, and (ii) expected long-term growth. As explained in Appendix A, the model often is expressed in the familiar form $k = \frac{D(1+g)}{P_0} + g$, where the expected dividend yield generally equals the expected annual dividend divided by the current stock price, and the growth rate is based on analysts' expectations of earnings growth. The Constant Growth DCF formula, which falls from the longer "present value" structure,[19] requires several simplifying assumptions, including the constancy of inputs in perpetuity.

Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[20] Given that assumption, it does not matter whether the investor holds the stock in perpetuity, or whether they hold the stock for some period of time, collect the dividends, then sell at the prevailing market price. That result also requires that the ROE result reached today will remain unchanged in perpetuity. So, if market conditions are such that the model produces an unreasonably low (or high) ROE estimate today,

---

18 Docket No. EL11-66-001, *et al.*, *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018), at para. 44 (italics in original).

19 Appendix A, part A.

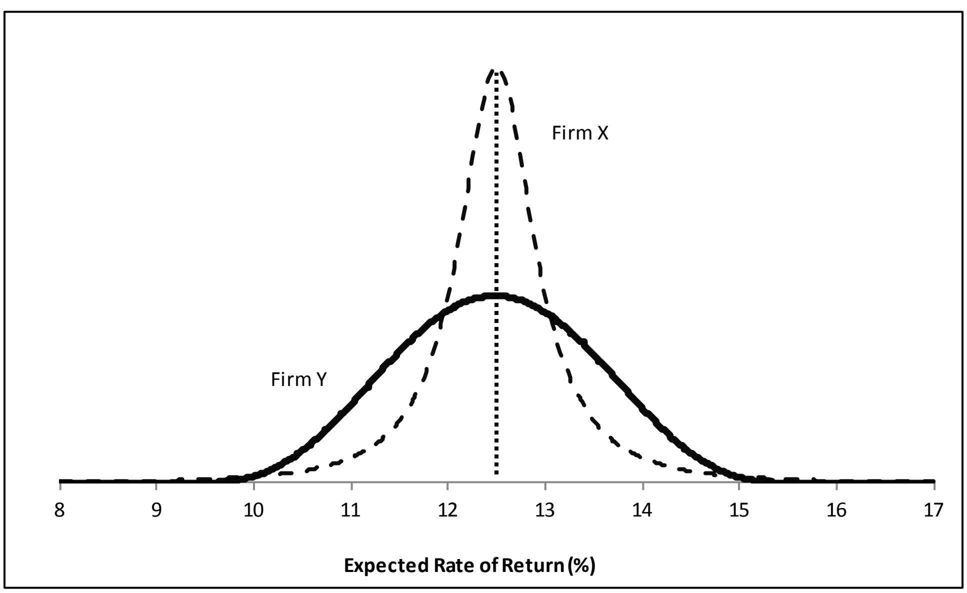
20 As discussed in Appendix A, part A, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity. Additionally, academic research has indicated that analysts forecasts of growth are superior to other measures of growth (*see* Appendix A, part A).

it assumes that estimate will be the same ROE investors require every day in the future, regardless of whether or how market conditions change.

Q. Please briefly describe the Capital Asset Pricing Model.

A. Whereas DCF models focus on expected cash flows, Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on additional risk. In finance, "risk" generally refers to the variation in expected returns, rather than the expected return, itself. Consider two firms, X and Y, with expected returns, and the expected variation in returns noted in Chart 1, below. Although the two have the same expected return (12.50 percent), Firm Y's are far more variable. From that perspective, Firm Y would be considered the riskier investment.

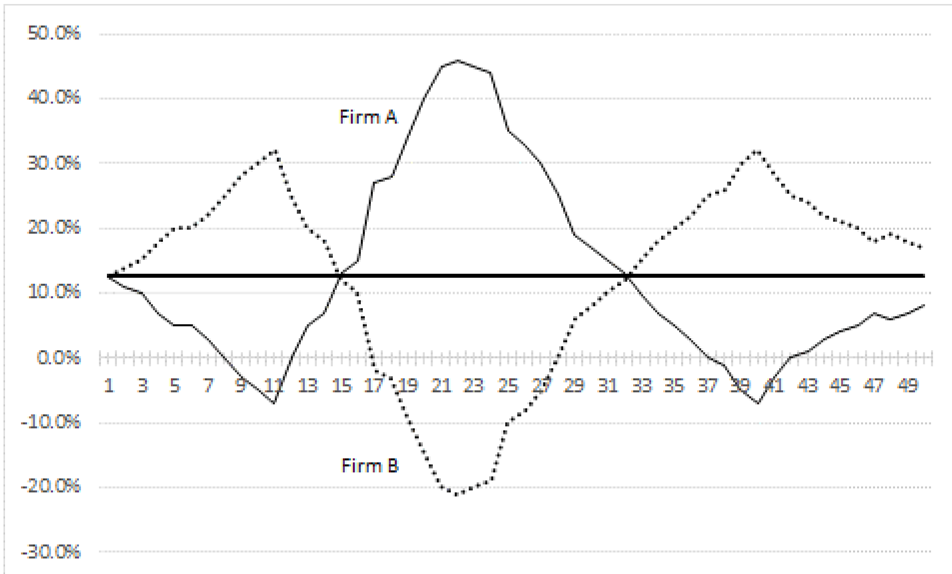
Chart 1: Expected Return and Risk



Now consider two other firms, Firm A and Firm B. Both have expected returns of 12.50 percent, and both are equally risky as measured by their volatility.

But as Firm A's returns go up, Firm B's returns go down. That is, the returns are negatively correlated.

Chart 2: Relative Risk



If we were to combine Firms A and B into a portfolio, we would expect a 12.50 percent return with no uncertainty because of the opposing symmetry of their risk profiles. That is, we can diversify the risk away. As long as two stocks are not perfectly correlated, we can achieve diversification benefits by combining them in a portfolio. That is the essence of the Capital Asset Pricing Model – because we can combine firms into a portfolio, the only risk that matters is the risk that remains after diversification, *i.e.*, the "non-diversifiable" risk.

The CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds. The risk-free rate essentially sets the baseline of the

CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (*i.e.*, the required return) and the risk-free rate is the risk premium.

Risk-Free Rate + Risk Premium = Cost of Equity [1]

The risk premium is defined as a security's Beta coefficient multiplied by the risk premium of the overall market (the "Market Risk Premium" or "MRP"). The Beta coefficient is a measure of the subject company's risk relative to the overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means the security is as risky as the overall market; a value below 1.00 represents a security with less risk than the overall market, and a value over 1.00 represents a security with more risk than the overall market.

Risk-Free Rate + (Beta Coefficient x Market Risk Premium) = Cost of Equity [2]

Given that the correlation between the proxy group companies and the S&P 500 has declined since 2014, while the relative risk has increased,[21] the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors for low-Beta companies. As such, I have considered the Empirical CAPM ("ECAPM") approach, which is a variant of the CAPM approach is the Empirical CAPM ("ECAPM") approach. The ECAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks.

21 *See* Chart 7, below.

Q. Please briefly describe the Bond Yield Plus Risk Premium approach.

A. This approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred to as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

Bond Yield + Equity Risk Premium = Cost of Equity [3]

Q. Please summarize your analytical results.

A. The results of the models described above are provided in Tables 6 and 7, below.[22]

Table 6: Summary of DCF Results[23]

	Mean Low	Mean	Mean High
30-Day Average	7.34%	9.64%	13.53%
90-Day Average	7.38%	9.68%	13.57%
180-Day Average	7.38%	9.68%	13.57%

22 *See* Appendix A for a more detailed description of the models, assumptions, and inputs described in Section IV.
23 Exhibit A-53 (RBH-1).

Table 7: Summary of Risk Premium Results[24]

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	9.13%	10.92%
Near Term Projected 30-Year Treasury (3.25%)	9.35%	11.13%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.32%	12.46%
Near Term Projected 30-Year Treasury (3.25%)	10.54%	12.68%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.26%	12.37%
Near Term Projected 30-Year Treasury (3.25%)	10.47%	12.59%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	11.15%	13.53%
Near Term Projected 30-Year Treasury (3.25%)	11.37%	13.75%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (3.03%)	9.89%	
Near Term Projected 30-Year Treasury (3.25%)	9.91%	
Long-Term Projected 30-Year Treasury (4.05%)	10.11%	

Q. Please briefly describe the Expected Earnings analysis.

A. The Expected Earnings analysis is based on the principle of opportunity costs. By taking historical returns on book equity and comparing those to authorized ROEs,

24 Exhibits A-57 (RBH-5) and A-58 (RBH-6).

investors are able to directly compare returns from investments of similar risk. In addition to historical returns, Value Line also provides projected returns on book equity. I have relied solely on forward-looking projections in the Expected Earnings analysis.[25] Those results range from 9.58 percent to 12.13 percent, with an average of 10.73 percent.[26] As noted earlier, I used those results to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results.[27]

V. BUSINESS RISKS AND OTHER CONSIDERATIONS

A. Small Size

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect."[28] While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, Ibbotson Associates noted:

> "For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return."[29]

Small size, therefore, leads to two categories of increased risk for investors: (i) liquidity risk (i.e., the risk of not being able to sell one's shares in a timely manner

---

25 As described more fully in Appendix A, an adjustment is necessary to accurately reflect the average invested capital over the period in question.
26 Exhibit A-59 (RBH-7).
27 Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs.* (November 15, 2018).
28 Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002, pages 368-397, for a review of literature relating to the size effect.
29 Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

due to the relatively thin market for the securities); and (ii) fundamental business risks.

Q. How does SEMCO Gas compare in size to the proxy companies?

A. Relative to the proxy group, SEMCO Gas is significantly smaller in terms of both average customers and annual revenues. Exhibit A-60 (RBH-8) estimates the implied market capitalization for SEMCO Gas. That is, because SEMCO Gas is not a separately traded entity, an estimated stand-alone market capitalization for SEMCO Gas must be calculated. The implied market capitalization of SEMCO Gas is calculated by applying the median market-to-book ratio for the proxy group of 2.19 to the Company's implied total common equity of $442.28 million.[30] The implied market capitalization based on that calculation is $966.63 million, which is less than 23.50 percent of the proxy group median of $4.12 billion.

Q. How does the comparatively small size of SEMCO Gas affect its business risks relative to the proxy group of companies?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. Capital expenditures for non-revenue producing investments such as system maintenance and replacements will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. These risks affect the return required by investors for smaller companies.

30 Equity value of SEMCO Gas is estimated from the proposed test year rate base in Exhibit A-12, Schedule B-1 and proposed capital structure in Exhibit A-14, Schedule D-1.

Q. Is there support in the financial community for the use of a small size premium?

A. Yes. There have been several studies that demonstrate the size premium. One of the earliest works in this area found that over a period of 40 years "the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[31] The author, who referred to that finding as the "size effect," suggested that the CAPM was mis-specified in that on average, smaller firms had significantly larger risk-adjusted returns than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[32] Since then, additional empirical research has focused on explaining the size effect as a function of lower trading volume and other factors, but the proposition that Beta fails to reflect the risks of smaller firms persists.[33]

In 1994, Fama and French focused on the issue of whether the CAPM adequately explained security returns and proposed a "three factor" model for expected security returns. Those factors include: (i) the covariance with the market, (ii) size, and (iii) financial risk as determined by the book-to-market ratio. As explained by Morningstar, Fama and French "found that the returns on stocks are better explained as a function of size and book-to-market value in addition to

---

31 R. W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics, 9, 1981.

32 *Id.*

33 *See*, *e.g.* Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March, 2002.

the single market factor of the CAPM, with the company's size capturing the size effect and its book-to-market ratio capturing the financial distress of a firm."[34]

Q. How did you estimate the size premium for SEMCO Gas?

A. In its *2019 Cost of Capital Navigator*, Duff & Phelps presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with SEMCO Gas, therefore, is the difference in the Duff & Phelps size risk premiums for the proxy group median market capitalization relative to the implied market capitalization for SEMCO Gas.

As shown on Exhibit A-60 (RBH-8), based on recent market data, the median market capitalization of the proxy group was approximately $4.12 billion, which corresponds to the fifth decile of Duff & Phelps's market capitalization data. Based on the Duff & Phelps analysis, that decile has a size premium of 1.28 percent (or 128 basis points). The implied market capitalization for SEMCO Gas is approximately $966.63 million, which falls within the eighth decile and corresponds to a size premium of 1.80 percent (or 180 basis points). The difference between those size premiums is 52 basis points (1.80 percent – 1.28 percent).

---

34 Morningstar, Ibbotson SBBI 2013 Valuation Yearbook, at 109.

Q. Have you considered the comparatively small size of SEMCO Gas in your ROE recommendation?

A. Yes. While I have quantified the small size effect, rather than proposing a specific premium, I have considered the small size of SEMCO Gas in my assessment of business risks in order to determine where, within a reasonable range of returns, SEMCO Gas's required ROE appropriately falls. In that regard, SEMCO Gas's comparatively small size further supports my conclusion that an ROE above the proxy group mean is reasonable.

B. Capital Expenditures

Q. What is the Company's planned capital expenditures over the test year?

A. SEMCO Gas currently plans to invest nearly $243.00 million during the 24-month period ending December 31, 2020.[35] That amount includes expenditures in both transmission and distribution facilities and to maintain safe, sufficient, and reliable service. As the Company moves forward with its capital spending plan, timely recovery of its capital costs is critical to mitigate the delay of capital recovery and execute its capital spending program.

Q. How do the Company's expected capital expenditures compare to the proxy group?

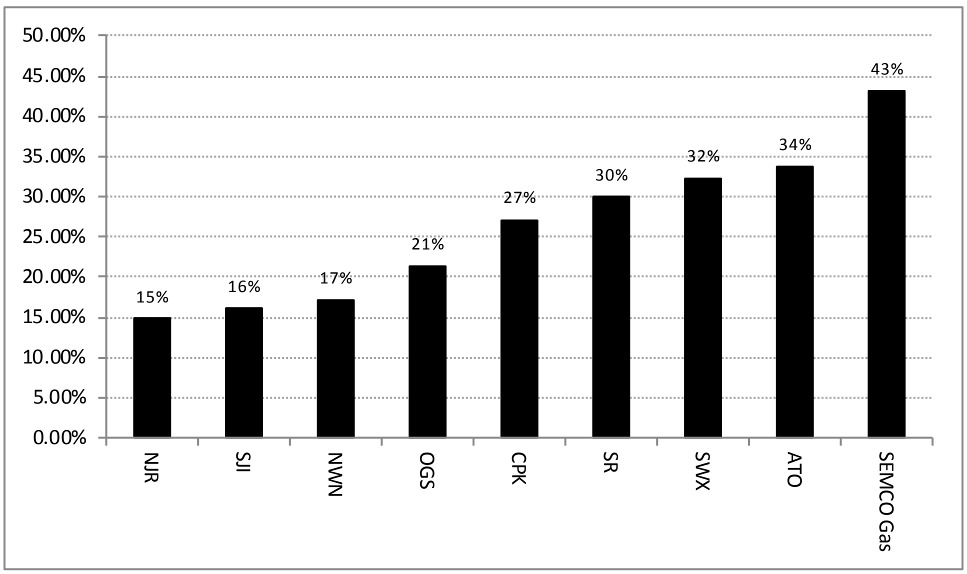
A. To reasonably make that comparison, I calculated the ratio of expected capital expenditures to net plant for each company in the proxy group. For the projected test year period 2019-2020, I performed that calculation using SEMCO Gas's

35 Source: Exhibit A-12, Schedule B-5.

projected capital expenditures relative to its 2018 net plant. As shown in Chart 3, relative to the proxy group, SEMCO Gas has the highest ratio of projected capital expenditures to net plant, approximately 19.00 percentage points more than the proxy group median.

Chart 3: Comparison of Projected Capital Expenditures

Relative to Net Plant[36]



Q. How do those considerations apply to Semco Gas and its capital spending plans?

A. It is clear SEMCO Gas's capital expenditure program is significant relative to the proxy group. It also is clear that the financial community recognizes the need for timely cost recovery for those capital expenditures. From a credit perspective, the additional pressure on cash flows associated with high levels of capital

36 Sources: Value Line Investment Survey; Exhibit A-12, Schedule B-5; SEMCO Energy Gas Company, MPSC Form P-522, Annual Report of Natural Gas Companies (December 31, 2018), at 200.

expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health including: heavy construction programs to address demand growth; declining capacity margins; and aging infrastructure and regulatory responsiveness to mounting requests for rate increases.[37] More recently, S&P noted that:

> We assume that capital spending will remain a focus of most utility managements and strain credit metrics. It provides growth when sales are diminished by ongoing demanded efficiency from regulators and other trends, and it is welcomed by policymakers that appreciate the economic stimulus and the benefits of safer, more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for it is an important factor in our assumptions and the forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and therefore ratings.[38]

Q. What are your conclusions regarding the effect of the Company's capital investment plan?

A. SEMCO Gas's capital expenditure plan relative to net plant is significantly larger than the proxy group companies. Although the Company is proposing capital cost recovery mechanisms, I understand that the capital costs projected for the test year are not included in those mechanisms. As discussed earlier in my testimony, the allowed ROE should enable the subject utility to finance capital expenditures

---

37 Standard & Poor's, *Industry Report Card: Utility Sectors in the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, RatingsDirect, June 27, 2008, at 4.

38 Standard & Poor's Rating Services, *Industry Top Trends 2017: Utilities*, RatingsDirect, February 16, 2017, at 4.

and working capital requirements at reasonable rates, and to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness.

The ratemaking process is based on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets. Consequently, the Commission's decision in this proceeding will directly affect the Company's ability to fund capital investments with operating cash flows, and the financial community's view of its financial profile.

VI. CAPITAL MARKET ENVIRONMENT

Q. Do economic conditions influence the required cost of capital and required return on common equity?

A. Yes. The models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent a given model's assumptions are misaligned with such data, or its results inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. Do you have any general observations regarding the relationship between current capital market conditions and the Company's Cost of Equity?

A. Yes. Although the Federal Reserve completed its Quantitative Easing initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate and began the process of monetary policy normalization.[39] A significant analytical issue is how investors likely will react as that process continues, and eventually is completed. For example, increasing interest rates may be seen as an indication of expanding macroeconomic growth, in which case we reasonably could expect the growth rate component of the DCF model to increase. At the same time, sectors that historically have included dividend-paying companies lost value, as increasing interest rates provide investors with alternative sources of current

39 Federal Reserve Press Release, December 16, 2015.

income, increasing dividend yields. Those dynamics likely affect other models in different ways, increasing the risk of focusing on a single method. A more reasoned approach is to understand the relationships among capital market and macroeconomic variables, and to consider how those factors may affect different models and their results.

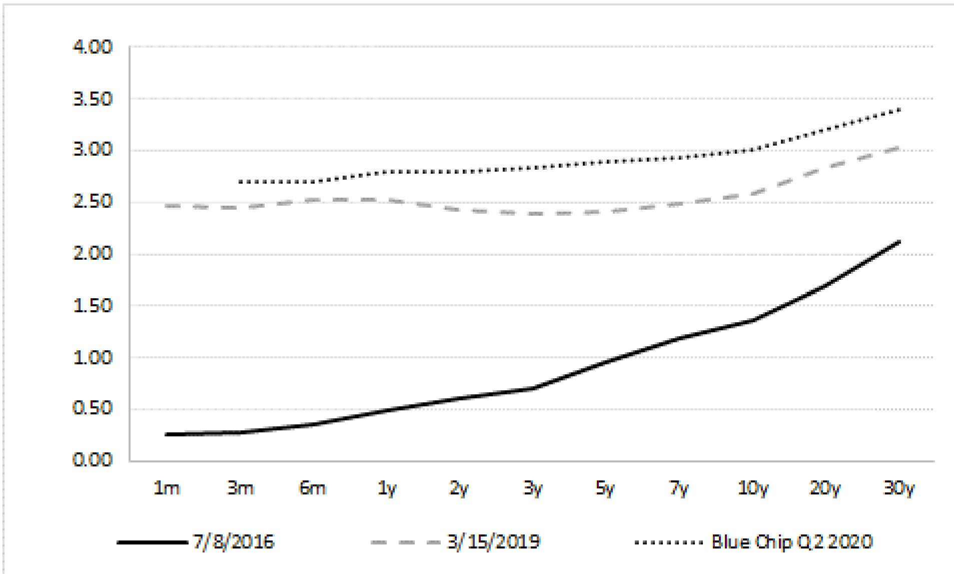
Q. Does your recommendation also consider the current interest rate environment?

A. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increased interest rates during the period in which the rates set in this proceeding will be in effect.

Although the Federal Reserve's market intervention policies kept interest rates historically low, since July 8, 2016 (when the 30-year Treasury yield fell to its secular low of 2.11 percent), interest rates have risen. As the Federal Reserve increased the Federal Funds target rate eight times between December 2016 and

December 19, 2018 to 2.25 percent – 2.50 percent, short-term and long-term interest rates also increased (*see* Chart 4 below).[40]

Chart 4: Treasury Yield Curve: 7/8/2016, 3/15/2019, and Projected Q2 2020[41]



In a press conference following the December 2018 Federal Open Market Committee meeting, Chairman Powell discussed the recent increases in the Federal Funds rate and the expectation for some further gradual rate increases, noting a strengthening economy, a strong labor market and rising wages.[42]

Aside from increases in the Federal Funds rate, in October 2017, the Federal Reserve initiated its balance sheet normalization program that includes gradual reductions to its security holdings by decreasing its reinvestment

---

40 Federal Reserve Board Schedule H.15. 1-year, 10-year and 30-year Treasury yields increased by 204 basis points, 122 basis points and 91 basis points, respectively, July 8, 2016 to March 15, 2019.

41 Sources: Federal Reserve Board Schedule H.15.; Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2. 3-year, 7-year, and 20-year projected Treasury yields interpolated.

42 Transcript of Chairman Powell's Press Conference, December 19, 2018.

activities.[43] In the January 2019 meeting, the Federal Reserve decided to continue with the balance sheet wind-down.[44] At the same time, the supply of marketable U.S. Treasury securities has increased by approximately $1.14 trillion.[45] The growing supply of Treasury securities from both the Federal Reserve and the U.S. Treasury puts upward pressure on Treasury rates.

Q. Does market-based data indicate that investors see a probability of increasing interest rates?

A. Yes. Consensus near-term forecasts of the 30-year Treasury yield reported by Blue Chip Financial Forecast indicate the market expects long-term rates to reach 3.40 percent by the second quarter of 2020. Importantly, the potential for rising rates represents risk for utility investors.

Q. Has market volatility changed with the Federal Reserve's move toward monetary policy normalization?

A. Yes, it has. A visible and widely reported measure of expected volatility is the Cboe Options Exchange ("Cboe") Volatility Index, often referred to as the VIX. As Cboe explains, the VIX "is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index (SPX℠) call and put options."[46] Simply,

---

43 https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee ("FOMC") Press Release, June 14, 2017.

44 *Federal Reserve Press Release* dated January 30, 2019.

45 Source: U.S. Treasury, Monthly Statement of the Public Debt. *See* https://www.treasurydirect.gov/govt/reports/pd/mspd/mspd.htm. U.S. marketable securities increased from $14.48 trillion to $15.62 trillion between December 31, 2017 and December 31, 2018.

46 Source: http://www.cboe.com/vix

the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator of expected increases in market risk.

Although the VIX is not expressed as a percentage, it should be understood as such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.67, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).[47]

As Chart 5 (below) demonstrates, in 2017 market volatility was well below its long-term average, and moved within a somewhat narrow range; the VIX averaged about 11.09, with a standard deviation of 1.36. Throughout 2018 and into 2019, the VIX average increased to 16.68 with a standard deviation of 4.77. That is, from 2017 to 2019 both the level and the volatility of market volatility increased.

47 Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.

Chart 5: VIX Since January 2017[48]

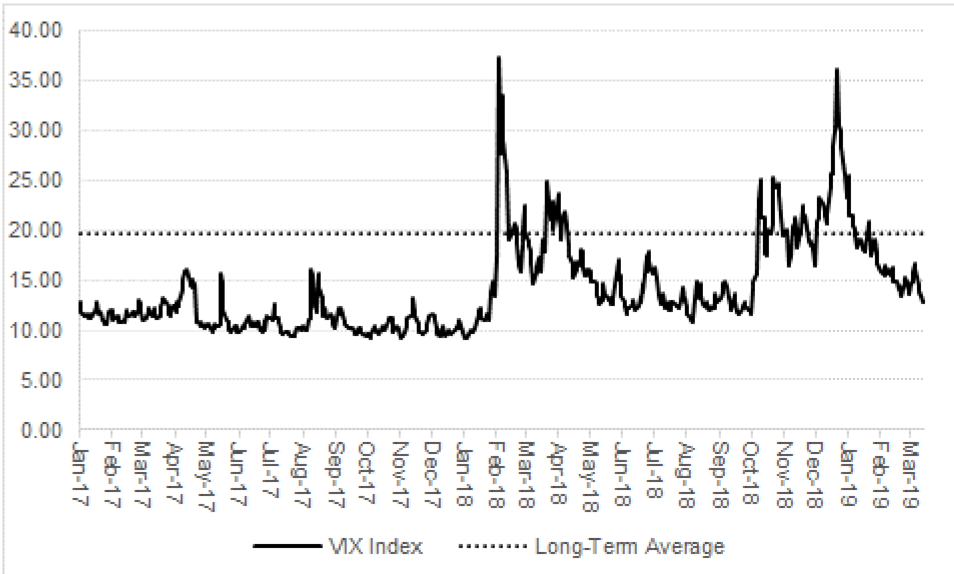


Table 8 (below) further demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.50 times higher than its 2017 level (1.36).

Table 8: VIX Levels and Volatility[49]

VIX Level and Volatility	
Long-term Average	19.67
2018-2019 Average	16.68
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.77
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

The increase in volatility is not surprising as market participants reassess

48 Source: Bloomberg Professional.
49 Source: Bloomberg Professional.

investment alternatives in light of the Federal Reserve's shift toward monetary policy and, as discussed below, the recent passage of new tax legislation.

Q. Is market volatility expected to increase from its current levels?

A. Yes, it is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[50]

Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. The expected VIX value in June 2020 is about 17.76, suggesting investors see a reversion to long-term average volatility over the coming months.[51] That increase in expected volatility makes intuitive sense, given the Federal Reserve's movement toward normalizing monetary policy. That policy change includes reducing the liquidity provided to the financial markets during the Federal Reserve's Quantitative Easing initiatives. Because that liquidity had the effect of dampening volatility as it was added to the markets, it stands to reason that volatility will increase as liquidity is diminished.

---

50 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.
51 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed March 15, 2019.

Q. Does the Federal Reserve's tightening of monetary policy have other implications for the assessment of capital markets?

A. Yes. It is important to recognize that the Federal Reserve's reduction in monetary stimulus is related to expectations of improved economic and financial conditions, and sustained growth in the overall economy. When increasing the Federal Funds rate on December 19, 2018, the Federal Open Market Committee noted the labor market continued to strengthen and that household spending was rising at a strong rate while business fixed investment had moderated from its rapid pace earlier in the year.[52] Although the Federal Reserve did not increase the Federal Funds rate in its January 2019 meeting, the Federal Open Market Committee observed the labor market continued to strengthen, and economic activity continued to rise at a solid rate.[53] From that perspective, we would expect to see higher growth estimates for companies in the overall economy, including the utility sector.

Q. What conclusions do you draw from your analyses of the current capital market environment, and how do those conclusions affect your ROE recommendation?

A. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE determination, including assessments of capital market conditions, are consistent with the conclusion itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and

52 *Federal Reserve Press Release* dated December 19, 2018.
53 *Federal Reserve Press Release* dated January 30, 2019.

the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, it is important to review and consider a variety of data points. That approach enables us to put in context both quantitative analyses and the associated recommendations. Further, because all models produce ranges of results, it is important to consider the type of information discussed above to determine where the Company's ROE falls within those ranges. As discussed throughout my testimony, doing so supports my recommended range of 10.00 percent to 10.75 percent.

VII. CAPITAL STRUCTURE

Q. What is the Company's proposed capital structure?

A. The Company has proposed a capital structure of 61.03 percent common equity and 38.97 percent long-term debt.[54]

Q. Are common equity and long-term debt the two debt sources of capital commonly considered in establishing a utility's ratemaking capital structure?

A. Yes, they are.

Q. Why is that the case?

A. The principal reason is that the assets included in rate base are long-lived, and they are financed with correspondingly long-lived securities. That is, utilities generally follow the financing practice commonly referred to as "maturity

54 Exhibit A-14, Schedule D-1.

matching," which matches the lives of assets being financed with the maturity of the securities issued to finance those assets. Under that practice, the overall term structure of the utility's long-term liabilities — including both debt and equity — correspond to the life of its long-term assets. As noted by Brigham and Houston:

> In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term sources.[55]

Whereas short-term debt has a maturity of one year or less, long-term debt may have maturities of 30 years or longer. Although there are practical financing constraints, such as the need to "stagger" long-term debt maturities, the general objective is to extend the average life of long-term debt. Still, long-term debt has a finite life, which is likely to be less than the life of the assets included in rate base. Common equity, on the other hand, is perpetual — its life is indefinite.

The perpetual nature of common equity makes it an important component of the capital structure. Because even long-term debt has a duration shorter than the average life of the rate base, common equity is needed to extend the capital structure's duration to more closely match that of the rate base. Short-term debt, on the other hand, will shorten the capital structure's average life, contrary to the practice of maturity matching. It would be unusual, therefore, for a natural gas utility such as the Company to fund its long-lived assets with short-term debt.

---

55 Brigham, Eugene F. and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, p. 574.

Q. Please explain why, in your view, short-term debt should be excluded from the ratemaking capital structure.

A. There are several reasons why short-term debt should be excluded. First, short-term debt generally is used to fund working capital requirements. Those requirements have a strong seasonal pattern; they are not permanent as are the assets included in rate base. Because short-term debt funds short-term working capital needs, it should not be included in the ratemaking capital structure.

Second, prudent financing practice calls for long-term assets (such as rate base items) to be financed with long-term securities. Doing otherwise would expose the Company's ratepayers to both refinancing risk (that is, the risk of not being able to roll-over short-term debt as it comes due), and interest rate risk (incurring higher interest costs as maturing short-term debt is refinanced). Although short-term debt may be used as an interim source of financing (that is, until a sufficiently large balance has been accumulated to be efficiently financed by long-term securities), it should not be seen as a permanent source of capital.

Q. If companies match the lives of their assets with the term of the securities financing them, can individual sources of financing be tracked to specific assets?

A. No, because cash is fungible, it is not feasible to track a given dollar from its source to its use. Rather, as noted by Brigham and Houston, companies tend to apply the more general maturity matching strategy (discussed above) under which short-term debt is borrowed to satisfy the overall, day-to-day, fluctuating, and somewhat unpredictable, cash needs, not to finance an individual utility function.

In that regard, daily cash requirements are a direct result of the timing associated with the receipt and disbursement of cash attributable to various activities, including supply-related working capital, non-supply-related working capital and for capital expenditures before permanent long-term financing has been obtained. Cash management, including issuing short-term debt, focuses on the overall daily cash needs; each specific element of working capital is not financed independently. In other words, daily cash requirements are not traceable to any specific working capital need, *e.g.,* supply-related working capital versus non-supply-related working capital.

Q. How does the capital structure affect the Cost of Equity?

A. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in its capital structure. As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also increases. That risk is particularly relevant given the long-lived nature of utility assets; the average useful life of the Company's utility plant in service is more than 30 years.[56] Because equity is perpetual and helps extend the average tenor of the securities financing the rate base, it is appropriate to consider the ratios of long-term debt and equity in determining the capital structure. Lastly, because

56 SEMCO Energy Gas Company, MPSC Form P-522, Annual Report of Natural Gas Companies (December 31, 2018), at 123.2. The Company's composite depreciation rate was 2.8 percent for both 2017 and 2016.

the capital structure can affect the subject company's overall level of risk,[57] it is an important consideration in establishing a just and reasonable rate of return.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. I calculated the average capital structure for each of the proxy group companies over the last eight quarters. As shown in Exhibit A-61 (RBH-9), the mean of the proxy group actual capital structures is 54.82 percent common equity and 45.18 percent long-term debt. The common equity ratios range from 44.19 percent to 68.28 percent. Based on that review, it is apparent that the Company's proposed capital structure is generally consistent with the capital structures of the proxy group companies.

Q. What is the basis for comparing SEMCO Gas's test period end capital structure to the average capital components of the proxy group?

A. Measuring the capital components of the proxy group at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is more appropriate to normalize the relative relationship between the capital components over a period of time when making the comparison to the Company's capital structure.

57 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

Q. What is your conclusion regarding an appropriate capital structure for SEMCO Gas?

A. Considering the proxy group companies' average common equity ratios range from 44.19 percent to 68.28 percent, I believe that SEMCO's proposed common equity ratio of 61.03 percent is appropriate as it is consistent with the proxy group companies.

VIII. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding the Company's Cost of Equity?

A. As discussed in Section IV and Appendix A (and as shown in Exhibit A-53 (RBH-1) through Exhibit A-59 (RBH-7)), I have performed several analyses to estimate SEMCO Gas's Cost of Equity. In light of those results, and taking into consideration other relevant and observable market data, including certain risk factors the Company faces, I believe that an ROE in the range of 10.00 percent to 10.75 percent represents the range of returns required by equity investors under current and expected market conditions. Within that range, I conclude that an ROE of 10.50 percent represents a reasonable estimate of the Cost of Equity for SEMCO Gas. Additionally, I conclude that the Company's proposed capital structure for the test year ending December 31, 2020, which includes 61.03 percent common equity and 38.97 percent long-term debt, is reasonable and appropriate.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

IX. Appendix A

A. Constant Growth Discounted Cash Flow Model

Q. Please more fully describe the Constant Growth DCF approach.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [4]$$

where P represents the current stock price, D_1 … D_∞ represent expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [5]$$

Equation [5] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term annual growth rate.

Q. What assumptions are inherent in the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) a constant dividend payout ratio in perpetuity; (3) the observed P/E ratio will remain constant in perpetuity; and (4) estimated Cost of Equity will remain constant, also in perpetuity.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield is based on each proxy company's current annualized dividend and average closing stock price over the 30-, 90-, and 180-trading day periods as of March 15, 2019, as explained more fully below.

Q. Why did you use three averaging periods to calculate an average stock price?

A. I did so to ensure the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-day averaging periods reasonably balances those concerns.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q. Is it important to select appropriate measures of long-term growth in applying the DCF model?

A. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [5] above) assumes a single growth estimate in perpetuity. Accordingly, to reduce the long-term growth rate to a single measure, one must assume a fixed payout ratio, and the same constant growth rate for earnings per share ("EPS"), dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. This can be accomplished by averaging those measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. Therefore, for the purposes of the Constant Growth DCF model, growth in EPS represents the appropriate measure of long-term growth.

Q. Please summarize the findings of academic research on the appropriate measure for estimating equity returns using the DCF model.

A. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[58] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has

58 *See for example*, Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management, Spring 1986.

assumed increased emphasis in rate cases.[59]

Phillips' conclusion continues to hold true. Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[60] For example, Vander Weide and Carleton state that, "[our] results…are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[61] Other research specifically has noted the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices."[62] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[63] As Brigham, Shome and Vinson noted, "evidence in the current literature indicates that (i) analysts' forecasts are

59 Charles F. Phillips, Jr., The Economics of Regulation, Revised Edition, 1969, Richard D. Irwin, Inc., at 285.

60 *See for example*, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

61 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

62 Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return, Financial Management, Spring 1986.

63 *Id*.

superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."[64]

To that point, the research of Carleton and Vander Weide found earnings growth projections had a statistically significant relationship to stock valuation levels, whereas dividend growth rates did not.[65] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth not dividend growth, is the appropriate estimate in the Constant Growth DCF model.

Q. Please summarize your inputs to the Constant Growth DCF model.

A. I applied the DCF model to the proxy group of natural gas utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended March 15, 2019, for the term P_0; and
- The annualized dividend per share as of March 15, 2019, for the term D_0.

I then calculated my DCF results using each of the following growth terms:

- The Zacks consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates;
- The Value Line long-term earnings growth estimates; and
- An estimate of retention growth.

64 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985.

65 *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988.

As explained below, I calculated a low, mean, and high DCF result for each proxy company (*see* Exhibit A-53 (RBH-1).

Q. Please describe the retention growth estimate as applied in your DCF model.

A. The Retention Growth model, which is a generally recognized and widely taught method of estimating long-term growth, is an alternative approach to the use of analysts' earnings growth estimates. The model estimates growth as a function of (i) expected earnings, and (ii) the extent to which earnings are retained. In its simplest form, the model represents long-term growth as the product of the retention ratio (i.e., the percentage of earnings not paid out as dividends (referred to below as "b") and the expected return on book equity (referred to below as "r")). Thus, the simple "b x r" form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The "br + sv" form of the Retention Growth estimate used in my DCF analysis is meant to reflect growth from both internally generated funds (i.e., the "br" term) and from issuances of equity (i.e., the "sv" term). The first term, which is the product of the retention ratio (i.e., "b", or the portion of net income not paid in dividends) and the expected Return on Equity (i.e., "r") represents the portion of net income that is "plowed back" into the Company as a means of funding growth. The "sv" term is represented as:

$$\left(\frac{M}{B}-1\right) \text{ x Growth rate in Common Shares} \qquad [6]$$

where $\frac{M}{B}$ is the Market-to-Book ratio. In this form, the "sv" term reflects an element of growth as the product of (a) the growth in shares outstanding, and (b) that portion of the market-to-book ratio that exceeds unity. As shown in Exhibit A-54 (RBH-2), all components of the Retention Growth model may be derived from data provided by Value Line.

Q. How did you calculate the mean high and mean low DCF results?

A. For each proxy company, I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, First Call, and the retention growth estimate, with the subject company's dividend yield. The mean high result simply is the average of those estimates. I used the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, First Call, and the retention growth estimate for each proxy company, and calculating the average result for those estimates.

Q. What are the results of your Constant Growth DCF analysis?

A. My Constant Growth DCF results are summarized in Table 9 below (*see also* Exhibit A-53 (RBH-1)).

Table 9: Mean Constant Growth DCF Results[66]

	Mean Low	Mean	Mean High
30-Day Average	7.34%	9.64%	13.53%
90-Day Average	7.38%	9.68%	13.57%
180-Day Average	7.38%	9.68%	13.57%

66 Exhibit A-53 (RBH-1).

B. CAPM Analysis and Empirical CAPM Analysis

Q. Please briefly describe the general form of the CAPM analysis.

A. The CAPM analysis is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [6], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [6]$$

where:

K_e = the required market ROE for a security;

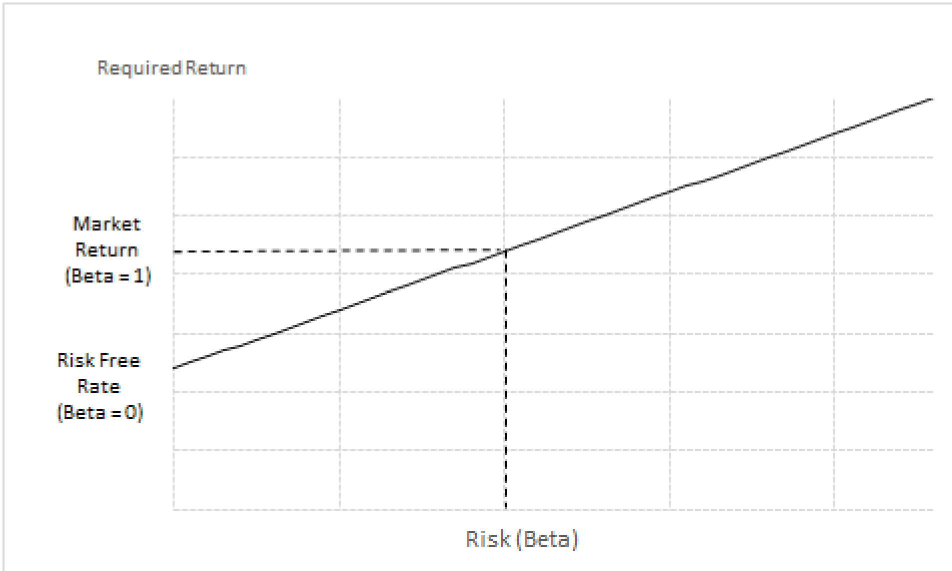
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Equation [6] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 6 below. The intercept is the risk-free rate (r_f), which has a Beta coefficient of zero, the slope is the expected Market Risk Premium ($r_m - r_f$). By definition, r_m, the return on the market has a Beta coefficient of 1.00. Under the CAPM, the expected Equity Risk Premium for a given security is proportional to its Beta coefficient.

Chart 6: Security Market Line



In Equation [6], the term ($r_m - r_f$) represents the Market Risk Premium.[67] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to investment portfolios, the market will not compensate investors for bearing that risk. Therefore, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad [7]$$

where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. The Beta coefficient therefore represents both relative volatility (*i.e.*,

67 The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Intuitively, companies with higher Beta coefficients have had more volatile returns, and have moved more closely with the overall market. The implication is that a company with a Beta coefficient of 1.00 is as risky as the overall market; companies with Beta coefficients less than 1.00 are less risky, and those whose Beta coefficients are greater than 1.00 have greater risk than the overall market.

Q. What assumptions did you include in your CAPM analysis?

A. Because utility assets represent long duration investments, I used two different measures of the risk-free rate: (i) the current 30-day average yield on 30-year Treasury bonds (3.03 percent);[68] and (ii) the projected 30-year Treasury yield (3.25 percent).[69]

Q. Why have you relied on the 30-year Treasury yield for your CAPM analysis?

A. In determining the risk-free rate, it is important to select the term (or maturity) that best matches the life of the underlying investment. Natural gas distribution utilities typically are long-duration investments and as such, the 30-year Treasury yield is most suitable for the purpose of calculating the Cost of Equity.

Q. Please describe your *ex-ante* (*i.e.*, forward-looking) approach to estimating the Market Risk Premium.

A. The approach is based on the market required return, less the current 30-year Treasury yield. To estimate the market required return, I calculated the market

68 Source: Bloomberg Professional.
69 Blue Chip Financial Forecast, Vol. 38, No. 3, March 1, 2019, at 2.

capitalization weighted average ROE based on the Constant Growth DCF model. To do so, I relied on data from two sources: (i) Bloomberg; and (ii) Value Line. With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the S&P 500 companies for which Bloomberg provided consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* market risk premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit A-55 (RBH-3).

Q. How did you apply your expected Market Risk Premium and risk-free rate estimates?

A. I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury yields as inputs to my CAPM analyses.

Q. What Beta coefficient did you use in your CAPM model?

A. As shown in Exhibit A-56 (RBH-4), I considered Beta coefficients reported by two sources, Bloomberg and Value Line. Although both services adjust their calculated (or "raw") Beta coefficients to reflect the tendency to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. What are the results of your CAPM analysis?

A. As shown in Table 10 (below) the CAPM analyses suggest an ROE range of 9.13 percent to 12.68 percent (*see also* Exhibit A-57 (RBH-5)).

Table 10: Summary of CAPM Results[70]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	9.13%	10.92%
Near Term Projected 30-Year Treasury (3.25%)	9.35%	11.13%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.32%	12.46%
Near Term Projected 30-Year Treasury (3.25%)	10.54%	12.68%

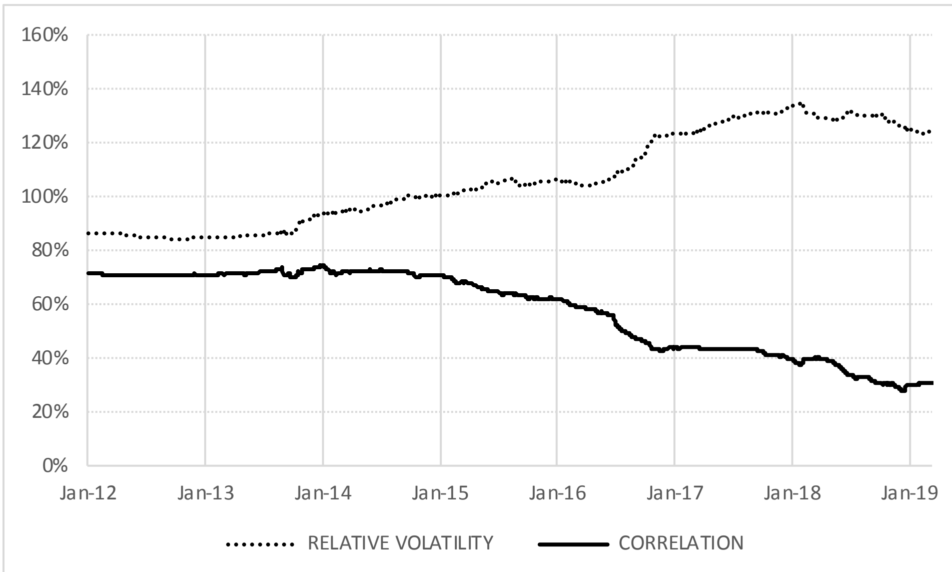
Q. Does the recent decline in the proxy group average Beta coefficient imply a decrease in risk relative to the market?

A. Not necessarily. Although the proxy group average Beta coefficient reported by Bloomberg has fallen from approximately 0.72 in 2014 to 0.57 in March 2019, as Chart 7 below demonstrates, when the Beta coefficient is deconstructed into its components shown in Equation [7] above, we see that the correlation between the proxy group companies and the S&P 500 has declined, while the relative risk has increased. Given that the correlation between the proxy group companies and the S&P 500 has declined since 2014, while the relative risk has increased, the CAPM in the form presented here may not adequately reflect the expected systematic

70 *See* Exhibit A-57 (RBH-5).

risk, and therefore, the returns required by investors in low-Beta companies such as utilities.

Chart 7: Components of Beta Coefficients Over Time[71]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I also included the ECAPM approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[72] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [8] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [8]$$

71 Source: S&P Global Market Intelligence. Calculated as an index.
72 *See e.g.*, Roger A. Morin, *New Regulatory Finance* 189-90 (2006).

where:

k_e = the required market ROE.

β = Adjusted Beta coefficient of an individual security.

r_f = the risk-free rate of return.

r_m = the required return on the market as a whole.

Q. What is the benefit of the ECAPM approach?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[73]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual Security Market Line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML.[74] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[75] Similarly, Morin states:

With few exceptions, the empirical studies agree that . . . low-beta

73 *Id*. at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

74 *Id*. at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

75 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

> securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[76]
>
> ***
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [77]

Some analysts claim that using adjusted Beta coefficients addresses the empirical issues with the CAPM by increasing the expected returns for low Beta stocks and decreasing the returns for high Beta stocks, concluding that there is no need for the ECAPM approach. I disagree with that conclusion. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This

76 Roger A. Morin, PhD, *New Regulatory Finance,* at 175.
77 Roger A. Morin, *New Regulatory Finance*, at 190, footnote 12 (2006).

> is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. [78]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of my ECAPM analyses shown in Exhibit A-57 (RBH-5) and summarized in Table 11 below.

Table 11: Summary of ECAPM Results[79]

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.26%	12.37%
Near Term Projected 30-Year Treasury (3.25%)	10.47%	12.59%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	11.15%	13.53%
Near Term Projected 30-Year Treasury (3.25%)	11.37%	13.75%

78 *Id.* at 191. Figure 6-1 is a figure in Dr. Morin's textbook.

79 *See* Exhibit A-57 (RBH-5).

C. Bond Yield Plus Risk Premium Approach

Q. Please generally describe the Bond Yield Plus Risk Premium approach.

A. This approach is based on the basic financial principle that because equity investors bear the residual risk associated with ownership, they require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds. As noted in my discussion of the CAPM, because the equity risk premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking estimates of the Cost of Equity, and others that consider historical, or *ex-post*, estimates. An alternative approach is to use actual authorized returns for natural gas utilities to estimate the Equity Risk Premium.

Q. Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A. As suggested above, I first defined the Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (*i.e.*, 30-year) Treasury yield. I then gathered data for 1,117 natural gas utility rate proceedings between January 1980 and March 15, 2019. In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (the "lag period"). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 187 days).

Because the data cover multiple economic cycles, the analysis also may be used to assess the stability of the Equity Risk Premium. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates. That analysis is particularly relevant given the relatively low, but increasing level of current Treasury yields.

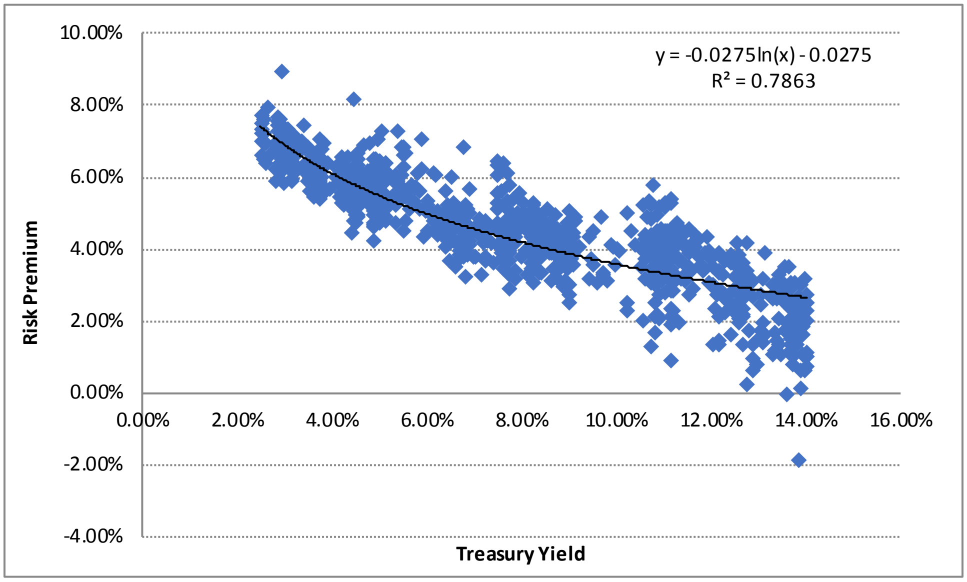
Q. How did you model the relationship between interest rates and the Equity Risk Premium?

A. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$\text{RP} = \alpha + \beta\left(LN(T_{30})\right) \quad [9]$$

As shown on Chart 8 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 8: Equity Risk Premium[80]



As Chart 8 illustrates, the Equity Risk Premium increases as interest rates fall. That finding, that there an inverse relationship between interest rates and the Equity Risk Premium is supported by published research. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[81] Consequently, simply applying the long-term average Equity Risk Premium of 4.69 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 8,

80 *See* Exhibit A-58 (RBH-6).
81 Roger A: Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added]

however, the implied ROE is between 9.89 percent and 10.11 percent (*see* Table 12 below and Exhibit A-58 (RBH-6)).

Table 12: Summary of Bond Yield Plus Risk Premium Results[82]

	Return on Equity
Current 30-Year Treasury (3.03%)	9.89%
Near-Term Projected 30-Year Treasury (3.25%)	9.91%
Long-Term Projected 30-Year Treasury (4.05%)	10.11%

D. Expected Earnings Analysis

Q. Please describe the Expected Earnings analysis

A. The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in, and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. Please explain how the Expected Earnings analysis is conducted.

A. The Expected Earnings analysis typically takes the actual earnings on book value of investment for each of the members of the proxy group and compares those values to the rate of return in question. Although the traditional approach uses data based on historical accounting records, it is common to use forecasted data

82 *See* Exhibit A-58 (RBH-6).

in conducting the analysis. Projected returns on book investment are provided by various industry publications (*e.g.,* Value Line), which I have used in my analysis.

I relied on Value Line's projected Return on Common for the period 2022-2024, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[83] The results range from 9.58 percent to 12.13 percent, with an average value of 10.73 percent and median value of 10.41 percent (*see* Exhibit A-59 (RBH-7)).

83 The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. *See* Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

scottmadden
MANAGEMENT CONSULTANTS

Attachment A
Resume of:
Robert B. Hevert, Partner
Rates, Regulation & Planning Practice Leader

Summary

Bob Hevert is a financial and economic consultant with more than 30 years of broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. He has provided expert testimony on a wide range of financial, strategic, and economic matters on more than 250 occasions at the state, provincial, and federal levels.

Prior to joining ScottMadden, Bob served as managing partner at Sussex Economic Advisors, LLC. Throughout the course of his career, he has worked with numerous leading energy companies and financial institutions throughout North America. He has provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues. Bob earned a B.S. in business and economics from the University of Delaware and an M.B.A. with a concentration in finance from the University of Massachusetts at Amherst. Bob also holds the Chartered Financial Analyst designation.

Areas of Specialization

- Regulation and rates
- Utilities
- Fossil/hydro generation
- Markets and RTOs
- Nuclear generation
- Mergers and acquisitions
- Regulatory strategy and rate case support
- Capital project planning
- Strategic and business planning

Recent Expert Testimony Submission/Appearance

- Federal Energy Regulatory Commission – Return on Equity
- New Jersey Board of Public Utilities – Merger Approval
- New Mexico Public Regulation Commission – Cost of Capital and Financial Integrity
- United States District Court – PURPA and FERC Regulations
- Alberta Utilities Commission – Return on Equity and Capital Structure

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies, the Alberta Utilities Commission, and the Federal Energy Regulatory Commission
- For an independent electric transmission provider in Texas, prepared an expert report on the economic damages with respect to failure to meet guaranteed completion dates. The report was filed as part of an arbitration proceeding and included a review of the ratemaking implications of economic damages
- Advised the board of directors of a publicly traded electric and natural gas combination utility on dividend policy issues, earnings payout trends and related capital market considerations
- Assisted a publicly traded utility with a strategic buy-side evaluation of a gas utility with more than $1 billion in assets. The assignment included operational performance benchmarking, calculation of merger synergies, risk analysis, and review of the regulatory implications of the transaction
- Provided testimony before the Arkansas Public Service Commission in support of the acquisition of SourceGas LLC by Black Hills Corporation. The testimony addressed certain balance sheet capitalization and credit rating issues
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas power markets and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 General Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/19	Southwest Gas Corporation	Docket No. G-01551A-19-0055	Return on Equity
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
Southwestern Electric Power Company	02/19	Southwestern Electric Power Company	Docket No. 19-008-U	Return on Equity
Oklahoma Gas and Electric Company	09/16	Oklahoma Gas and Electric Company	Docket No. 16-052-U	Return on Equity
SourceGas Arkansas, Inc.	12/15	SourceGas Arkansas, Inc.	Docket No. 15-078-U	Response to Direct Testimony by Arkansas Attorney General related to Compliance Issues
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	04/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	11/17	Connecticut Light and Power Company	Docket No. 17-10-46	Return on Equity
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Council of the City of New Orleans				
Entergy New Orleans, LLC	09/18	Entergy New Orleans, LLC	Docket No. UD-18-07	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0977 (Electric)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0978 (Gas)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-649 (Electric)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-650 (Gas)	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	12/17	Potomac Electric Power Company	Formal Case No. 1150	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Formal Case No. 1139	Return on Equity
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. 1137	Return on Equity
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. 1103-2013-E	Return on Equity
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity
Federal Energy Regulatory Commission				
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
NextEra Energy Transmission West, LLC	07/15	NextEra Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hawaii Public Utilities Commission				
Hawai'i Electric Light Company, Inc.	12/18	Hawai'i Electric Light Company, Inc.	Docket No. 2018-0368	Return on Equity
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity
Hawai'i Electric Light Company, Inc.	09/16	Hawai'i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company, Inc.	06/14	Hawaiian Electric Company, Inc.	Docket No. 2013-0373	Return on Equity
Hawai'i Electric Light Company, Inc.	08/12	Hawai'i Electric Light Company, Inc.	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/18	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 18-0463	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	04/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Indiana Michigan Power Company	7/17	Indiana Michigan Power Company	Cause No. 44967	Return on Equity
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches
Kansas Corporation Commission				
Empire District Electric Company	02/19	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Empire District Electric Company	12/18	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Alternative Ratemaking Mechanisms
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff related to the ratemaking capital structure processes
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc.	05/17	Northern Utilities, Inc.	Docket No. 2017-00065	Return on Equity
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Washington Gas Light Company	04/19	Washington Gas Light Company	Case No. 9605	Return on Equity
Potomac Electric Power Company	01/19	Potomac Electric Power Company	Case No. 9602	Return on Equity
Washington Gas Light Company	05/18	Washington Gas Light Company	Case No. 9481	Return on Equity
Potomac Electric Power Company	01/18	Potomac Electric Power Company	Case No. 9472	Return on Equity
Delmarva Power & Light Company	07/17	Delmarva Power & Light Company	Case No. 9455	Return on Equity
Potomac Electric Power Company	03/17	Potomac Electric Power Company	Case No. 9443	Return on Equity
Delmarva Power & Light Company	06/16	Delmarva Power & Light Company	Case No. 9424	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Case No. 9418	Return on Equity
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/19	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 18-64/DPU 18-65/DPU 18-66	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83D
National Grid	11/18	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 18-150	Return on Equity
NSTAR Electric Company d/b/a Eversource Energy	11/18	NSTAR Electric Company d/b/a Eversource Energy	DPU 18-76/DPU 18-77/DPU 18-78	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83C
Boston Gas Company, Colonial Gas Company each d/b/a National Grid	11/17	Boston Gas Company, Colonial Gas Company each d/b/a National Grid	DPU 17-170	Return on Equity
NSTAR Electric Company Western and Massachusetts Electric Company each d/b/a Eversource Energy	01/17	NSTAR Electric Company Western Massachusetts Electric Company each d/b/a Eversource Energy	DPU 17-05	Return on Equity
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Michigan Public Service Commission				
Indiana Michigan Power Company	05/17	Indiana Michigan Power Company	Case No. U-18370	Return on Equity
Minnesota Public Utilities Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/17	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-17-285	Return on Equity
ALLETE, Inc., d/b/a Minnesota Power Inc.	11/16	ALLETE, Inc., d/b/a Minnesota Power Inc.	Docket No. E015/GR-16-664	Return on Equity
Otter Tail Power Corporation	02/16	Otter Tail Power Company	Docket No. E017/GR-15-1033	Return on Equity
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company -Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a Ameren Missouri	12/18	Union Electric Company d/b/a Ameren Missouri	Case No. GR-2019-0077	Return on Equity
KCP&L Greater Missouri Operations Company	01/18	KCP&L Greater Missouri Operations Company	Case No. ER-2018-0146	Return on Equity
Kansas City Power & Light Company	01/18	Kansas City Power & Light Company	Case No. ER-2018-0145	Return on Equity
Laclede Gas Company and Missouri Gas Energy	11/17	Laclede Gas Company and Missouri Gas Energy	Case No. GR-2017-0215 Case No. GR-2017-0216	Goodwill Adjustment on Capital Structure
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	09/17	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	Case No. GR-2018-0013	New Ratemaking Mechanisms
Union Electric Company d/b/a Ameren Missouri	07/16	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2016-0179	Return on Equity (electric)
Kansas City Power & Light Company	07/16	Kansas City Power & Light Company	Case No. ER-2016-0285	Return on Equity (electric)
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	05/18	Southwest Gas Corporation	Docket No. 18-05031	Return on Equity (gas)
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	06/17	Northern Utilities, Inc.	Docket No. DG 17-070	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	04/17	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 17-048	Return on Equity
Unitil Energy Systems, Inc.	04/16	Unitil Energy Systems, Inc.	Docket No. DE 16-384	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	04/16	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 16-383	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Elizabethtown Gas Company	04/19	Elizabethtown Gas Company	Docket No. GR19040486	Return on Equity
Atlantic City Electric Company	10/18	Atlantic City Electric Company	Docket No. EO18020196	Return on Equity
Atlantic City Electric Company	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
North Carolina Utilities Commission				
Piedmont Natural Gas Company, Inc.	04/19	Piedmont Natural Gas Company, Inc.	Docket No. G-9, Sub 743	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/19	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 562	Return on Equity
Duke Energy Carolinas, LLC	08/17	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1146	Return on Equity
Duke Energy Progress, LLC	06/17	Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Return on Equity
Public Service Company of North Carolina, Inc.	03/16	Public Service Company of North Carolina, Inc.	Docket No. G-5, Sub 565	Return on Equity
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
Empire District Electric Company	03/19	Empire District Electric Company	Cause No. PUD201800133	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	02/19	The Narragansett Electric Company d/b/a National Grid	Docket No. 4929	Support for financial remuneration under new power purchase agreement
The Narragansett Electric Company d/b/a National Grid	11/17	The Narragansett Electric Company d/b/a National Grid	Docket No. 4770	Return on Equity (electric & gas)
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	11/18	Duke Energy Carolinas, LLC	Docket No. 2018-319-E	Return on Equity
Duke Energy Progress, LLC	11/18	Duke Energy Progress, LLC	Docket No. 2018-318-E	Return on Equity
South Carolina Electric & Gas	08/18	South Carolina Electric & Gas	Docket No. 2017-370-E	Return on Equity
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity
Duke Energy Progress, LLC	07/16	Duke Energy Progress, LLC	Docket No. 2016-227-E	Return on Equity
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	04/18	Otter Tail Power Company	Docket No. EL18-021	Return on Equity (electric)
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
CenterPoint Energy Houston Electric LLC	04/19	CenterPoint Energy Houston Electric LLC	Docket No. 49421	Return on Equity
Texas-New Mexico Power Company	05/18	Texas-New Mexico Power Company	Docket No. 48401	Return on Equity
Entergy Texas, Inc.	05/18	Entergy Texas, Inc.	Docket No. 48371	Return on Equity
Southwestern Public Service Company	08/17	Southwestern Public Service Company	Docket No. 47527	Return on Equity
Oncor Electric Delivery Company, LLC	03/17	Oncor Electric Delivery Company, LLC	Docket No. 46957	Return on Equity
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Return on Equity
Southwestern Electric Power Company	12/16	Southwestern Electric Power Company	Docket No. 46449	Return on Equity (electric)
Sharyland Utilities, L.P.	04/16	Sharyland Utilities, L.P.	Docket No. 45414	Return on Equity
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Tex Division	10/18	Atmos Energy Corporation – Mid-Tex Division	GUD 10779	Return on Equity
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	03/19	Virginia Electric and Power Company	Case No. PUR-2019-00050	Return on Equity
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Reports

United States District Court, District of South Carolina, Columbia Division				
South Carolina Electric & Gas Company	07/18	South Carolina Electric & Gas Company	Case No. 3:18-CV-01795-JMC	Return on Equity
United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations
American Arbitration Association				
Confidential Client	11/14	Confidential Client	Confidential	Economic harm related to failure to perform

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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF KATIE L. SINGER

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Katie L. Singer
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. Katie L. Singer, 1411 Third Street, Suite A, Port Huron Michigan 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 the Director of Engineering.

Q. Please describe your educational background and business experience.

A. I graduated from Michigan State University in May 2002 with a Bachelor of Science degree in Electrical Engineering. Upon graduation, I accepted a position with Consumers Energy as a Circuit Engineer, with responsibilities for planning and maintaining the electric distribution system. In March 2011, I accepted an engineering position with DTE Energy as an engineer in its Electrical/I&C Plant Support Group at Fermi 2 Nuclear Power Plant. My natural gas industry related experience began in October 2011, when I accepted an engineering position at SEMCO Gas. In January 2014, I promoted to the position of Engineering Supervisor followed by Engineering Manager in April of 2015. I attained the position of Regional Operations Manager in December of 2016, and in 2017 I was promoted to my current position as Director of Engineering.

Q. What are your responsibilities as Director of Engineering?

A. I am responsible for the oversight of the design of all transmission and distribution lines and facilities and subsequent integrity management programs. I manage the Company's storage and environmental activities, and I am responsible for the development and monitoring of the Company's capital budget. I also serve as the pipeline construction contract administrator and oversee the Company's Geographic Information System ("GIS") department.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("Commission")?

A. Yes. I have filed testimony for SEMCO Gas's 2016-2017 gas cost recovery plan, Case No. U-17942. I have also filed testimony in support of the certificate of public convenience and necessity to construct and operate the Marquette Connector Pipeline, Case No. U-18202.

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

A. The purpose of my testimony is to address the following topics:

1) Projected Capital Expenditures
2) Main Replacement Program ("MRP")
3) Marquette Connector Pipeline ("MCP")
4) Rockford Valves
5) Environmental Manufactured Gas Plant ("MGP") sites
6) Incremental O&M Costs
7) Infrastructure Reliability Improvement Program ("IRIP")

Q. What exhibits are you sponsoring in this case?

A. I am sponsoring the following exhibits:

Exhibit A-12 (KLS-1), Schedule B-5: Historic & Projected Plant Additions
Exhibit A-20 (KLS-2): Leaks due to Corrosion on Mains and Services
Exhibit A-21 (KLS-3): Material Failure Leaks on Plastic Mains and Services
Exhibit A-22 (KLS-4): MRP/Base Mile History
Exhibit A-23 (KLS-5): Main Replacement Program
Exhibit A-24 (KLS-6): Marquette Connector Pipeline Project
Exhibit A-25 (KLS-7): Environmental Expenditures-MGP's
Exhibit A-26 (KLS-8): Incremental O&M Costs
Exhibit A-27 (KLS-9): Infrastructure Reliability Improvement Program Projects
Exhibit A-28 (KLS-10): Infrastructure Reliability Improvement Program

Q. Where these exhibits prepared by you or under your directions?

A. Yes.

<u>Historical and Proposed Capital Expenditures</u>

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

A. The purpose of this section of my testimony is to describe certain historical capital expenditures as well as the capital expenditures SEMCO Gas will make in 2019 and 2020. This information is used in the direct testimony and exhibits of Witness Tracy Vincent in determining plant and depreciation projections.

Q. What are SEMCO Gas's capital expenditures for 2019 and 2020?

A. As outlined in Exhibit A-12 (KLS-1), Schedule B-5, capital spending for 2019 is planned at \$40,469,094. Capital spending for 2020 is projected to be \$50,019,688. These expenditures fund improvements in the SEMCO Gas distribution and transmission systems needed to ensure the Company is capable of providing safe, efficient, and reliable service to customers. The lower capital spend in 2019, compared to 2018 and projected 2020, represents SEMCO Gas's 2019 focus on the completion of MCP. Costs relating to the MCP are separately discussed below.

Q. Please discuss the exhibit that details SEMCO Gas's historical capital spending and projected spending in 2019 and 2020 on various distribution and transmission system projects.

A. Exhibit A-12 (KLS-1), Schedule B-5 page 2, details SEMCO Gas's average capital expenditures, by plant type, for the last five years and the projected expenditures, also by plant type, for 2019 and 2020. As detailed in this exhibit, the average capital spending on system improvements from 2014 through 2018 was \$27,909,675 per year. The most significant plant expenditures were for distribution plant, at an average of \$23,395,331 annually. Exhibit A-12 (KLS-1), Schedule B-5 page 3, identifies the historic capital spending and projected spending in 2019 and 2020 for the Company's MRP.

Q. Please explain the capital expenditures associated with the Distribution Plant category in Exhibit A-12 (KLS-1), Schedule B-5 page 2.

A. The Distribution Plant category includes all new and replacement distribution mains, services, meters, regulators, customer meter and regulator sets, district regulator sets, and custody transfer gate stations, which are required to maintain safe, efficient, and reliable service to new and existing residential, commercial, and industrial customers. Expenditures in this category also include new and replacement installations for cathodic protection systems used to protect coated steel mains from corrosion.

As shown in Exhibit A-12 (KLS-1), Schedule B-5 page 2, the largest expenditures on Distribution Plant are for services, mains, and meters. These outlays are related primarily to the replacement of mains. This includes mains that are replaced as a result of state or municipal public improvement projects. Public road improvement projects and related public works activities generally require that SEMCO Gas relocate and replace facilities located in the affected public rights-of-way.

Q. Please explain the capital expenditures associated with the Transmission Plant category.

A. Capital expenditures for Transmission Plant primarily involve the replacement of transmission lines and the installation of gate stations as required to meet the natural gas demands of SEMCO Gas's customers. SEMCO Gas's system consists primarily of Distribution Plant, therefore, expenditures in this category are comparatively small.

Q. What are the capital expenditures associated with the Natural Gas Storage and Processing Plant category?

A. The Natural Gas Storage and Processing Plant category includes all storage pipeline, well work, meter and regulator stations, structures, and compressor equipment related to storage facilities used to provide service to customers. This category includes the costs of storage-related pipelines and equipment replacements and upgrades, including major compressor overhauls.

Q. What capital costs are included in the General Plant category?

A. The General Plant category includes all new or replacement technology and communication projects as well as miscellaneous tools. This category reflects the fact that computer systems are required to provide safe, efficient, and reliable service to SEMCO Gas customers. This category also includes tools and equipment necessary to perform routine and emergency work on all of SEMCO Gas's gas-handling systems. Lastly, this category also includes the purchase of buildings and associated furnishings with the exception of the purchase of our Headquarter office building shown separately in Exhibit A-12 (KLS-1), Schedule B-5 page 5.

Q. Will the capital expenditures proposed in Exhibit A-12 (KLS-1), Schedule B-5 page 2, enable SEMCO Gas to maintain safe, efficient, and reliable service to its customers?

A. Yes.

Q. Please discuss the relationship between the replacement of mains and other facilities as a result of state or municipal public improvement projects and other kinds of capital expenditures.

A. SEMCO Gas is focused on having a gas transmission and distribution system that provides safe, efficient, and reliable service to customers. Often times state and municipal public improvement projects require capital expenditures to be made on main replacements and relocations, even though existing facilities are in good condition. Because capital budgets are not limitless, the need to make expenditures associated with public road improvement projects and related public works activities often effectively defers capital expenditures on the replacement of aging infrastructure.

Main Replacement Program

Q. Please describe SEMCO Gas's MRP.

A. SEMCO Gas's MRP was designed to reduce corrosion leaks on metallic pipe and address safety issues related to vintage plastic mains and services. The MRP allows SEMCO Gas to replace 26 miles of qualifying main annually in addition to the 14.6 miles that has historically been replaced for a total of 40.6 miles of annual replacement. The MRP also allows SEMCO Gas to recover MRP related capital costs through a surcharge until the next general rate proceeding at which time these investments would become part of SEMCO Gas's rate base. The type of main qualifying for replacement includes unprotected steel and vintage plastic (pre-1978) pipe.

Q. In your opinion is this method of replacement the most cost-effective?

A. Yes. The most cost-effective way to replace corrosion-prone or vintage plastic facilities is a project-based approach that allows SEMCO Gas to plan the replacement work efficiently and systematically. The MRP has allowed the Company to do this. Aside from the regulatory aspects of the program, the underlying goal of the MRP is to mitigate the risk for pipeline failures comprehensively, by planning projects in advance, instead of replacing short sections of piping in a reactive fashion (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 SEMCO Gas system).

Q. Please describe the history of the MRP.

A. The Company's first MRP began in 2011 and ended in 2015. For the first two years (2011, and 2012) the Company targeted 21 miles of replacement pipe annually. The pipe identified for replacement consisted of unprotected metallic mains. In 2013, SEMCO Gas was allowed to increase annual mileage from 21 to 40.6. In addition to unprotected metallic, vintage plastic pipe was also approved for replacement for the remaining years of the program (2013-2015). In 2016 SEMCO Gas began its second MRP continuing to replace 40.6 miles of unprotected metallic or vintage plastic pipe annually. This program will be completed by the end of 2020. As discussed below, the Company intends seek approval to continue the program beyond 2020.

Q. What are some of the safety risks associated with unprotected metallic pipe?

A. Unprotected metallic pipe will corrode and leak. By removing this class of pipe from SEMCO Gas's system, risk of leakage and the related safety consequence to SEMCO Gas's customers and the general public is nearly eliminated. The elimination of this class of pipe also reduces the risk to SEMCO Gas's employees in repairing the leaks on this type of pipe. When this pipe is found to be leaking, the repair almost always involves exposing the leaking main, cleaning the surface rust, and installing a suitable leak clamp to stop the gas from escaping. This task is dangerous due to the fact that employees must work with live gas while repairing these leaks and even after the leak is repaired; the main can still fail as the pipe is being coated or backfilled exposing employees to fire and asphyxiation risks. Several incidents that have occurred in the natural gas industry are due to the failure of unprotected metallic main. In January of 2011, a utility worker in Philadelphia was killed due to the failure of a cast iron main and resulting fire. In October of 2011, a MichCon employee was tragically asphyxiated while repairing a leak on a cast iron main. Elimination of this class of pipe has and will continue to drastically reduce these risks to SEMCO Gas's employees, customers, and the general public.

Q. Please explain what SEMCO Gas considers vintage plastic pipe and why it should be replaced.

A. SEMCO Gas considers pre-1978 plastic pipe as vintage plastic. This pipe is prone to failure due to its known risk of cracking when subject to external stress due to ground movement from frost, construction or rock impingement. The failure mechanism is referred to as brittle crack failure and has been documented in various reports. In 1998, the National Transportation Safety Board issued a Special Investigative Report (NTSB/SIR-98/01) that described how plastic pipe installed from the 1960's through the early 1980's may be vulnerable to brittle crack failure that may result in gas leakage and potential hazards to the public and property. Subsequent advisory bulletins from the Pipeline and Hazardous Material Safety Administration offered additional information on brittle crack failure of plastic pipe. Leak rates have subsequently declined with the replacement of vintage plastic through the MRP.

Q. What other safety risks are inherent with vintage plastic pipe?

A. As discussed, the failure mode for vintage plastic pipe is usually a brittle fracture. When vintage plastic fails, it is normally more sudden and more catastrophic than a steel corrosion leak. This usually results in a more hazardous condition, for both the public as well as the crew performing the work. Typically, corrosion leaks on steel start out small and slowly become worse over time. In most cases, this allows time to detect and correct the corrosion leak before it becomes more serious. Vintage plastic brittle failures are usually without warning, sudden and significant. SEMCO Gas has found vintage plastic leaks are graded class one more often than leaks found on bare steel.

Q. What has been the result of the MRP on corrosion leaks?

A. Corrosion leaks on the Company's system have declined steadily with the onset of the MRP. Exhibit A-20 (KLS-2) represents the number of corrosion leaks on mains and services from the onset of the MRP. Corrosion leaks have decreased annually, accounting for a 67% reduction since the program started in 2011 through 2018.

Q. What has been the result of the MRP on other leaks?

A. Material failure leaks on the Company's system on plastic mains and services have declined since the inclusion of vintage plastic in the program in 2013 (Case No. U-17169). Exhibit A-21 (KLS-3) illustrates this trend. The first bar on Exhibit A-21 (KLS-3) represents the average material failure leaks occurring on plastic mains and services prior to qualifying this pipe type within the program (2011 through 2012). The second bar represents the average material failure leaks per year that have occurred since inception of vintage plastic in the program (2013-2018). This decline indicates that the replacement of vintage plastic main is positively affecting the material failure leak rate on plastic main and services.

Q. What other safety related benefits has SEMCO Gas experienced due to the MRP?

A. The MRP allows SEMCO Gas to accelerate the installation of Excess Flow Valves ("EFVs") on residential homes. EFVs automatically stop the flow of gas when a residential service line begins leaking. SEMCO Gas has installed nearly 14,000 more EFVs attributable to the increased renewal of residential service lines associated with mains replaced under the MRP.

The MRP also allowed SEMCO Gas to accelerate meter move outs. It has been more efficient to move meters out as part of a MRP project as opposed to doing scattered move outs. SEMCO Gas has eliminated all non-required residential inside meters.

Q. What other milestones have you achieved through the MRP?

A. Through the MRP, SEMCO Gas has eliminated all cast, wrought, and ductile iron pipelines.

Q. Has SEMCO Gas met all the requirements of the program as related to mileage and spend?

A. Yes. Exhibit A-22 (KLS-4) illustrates this. The first set of bars compares required MRP mileage to the Company's actual mileage replaced. The second set of bars compares the same for base mileage. The required spend verse actual spend is shown in the third set of bars. The Company has exceeded requirements in both mileage and spend throughout the program.

Q. Please describe the economic benefits of the MRP?

A. SEMCO Gas has validated that doing main replacement projects of a larger scope allows SEMCO Gas to decrease the projected per mile cost of installing replacement mains and services despite increases in cost of materials, fuel, and wages. This is due to concentrating construction crews, project designers, and construction permit approvals in tighter geographic regions. This approach allows construction crews to concentrate in one area and eliminates frequent movement of equipment and crews to repair small pockets of mains throughout the service area.

Q. Please discuss how SEMCO Gas prioritizes the Replacement of unprotected metallic and vintage plastic main.

A. SEMCO Gas prioritizes the main for replacement based on the risk model developed within its Distribution Integrity Management Program ("DIMP"). The DIMP model takes data stored on distribution mains and services and calculates an overall risk score for each segment of distribution main. The DIMP model was created and is maintained using Uptime, a GIS software developed by DNV-GL and the Gas Technology Institute.

Q. Has the DIMP model highlighted high ranking projects outside of the scope of the MRP?

A. Yes. The Company has retired over 350 miles of main over the course of the MRP. As this pipe has been replaced the Company's risk scores associated with MRP qualified pipe have decreased. Additional projects that are not qualified under the current MRP are now ranking higher. Many of these projects include more planning and higher costs than that required of typical MRP projects. High pressure steel main that is currently cathodically protected is an example of higher ranking projects. High pressure pipelines have a greater consequence in the event of a failure, therefore the risk is higher.

Q. How does SEMCO Gas recover the costs to replace these projects?

A. SEMCO Gas funds these projects through its normal capital program.

Q. What other project costs are recovered through the Company's normal capital program?

A. The Company's capital program is utilized to fund all projects driven by public improvement activities and any system reliability or improvement projects identified by the Company. This includes station work critical to the safety and reliability of its system. Costs associated with the annual retirement of 14.4 miles of vintage replacement main as required under the current MRP is also funded through SEMCO Gas's normal capital program.

Q. Please explain how public improvement jobs have impacted the Company's capital budget?

A. When the MRP began, projects driven by public works often resulted in qualifying mileage being retired. As the Company has removed more vintage main it has found fewer projects are qualifying under the program. A significant amount of the Company's base budget is required to meet base mile requirements and complete public improvement work. This leaves less money to address projects that often have a higher risk rank than some MRP qualified pipe.

Q. Is SEMCO Gas proposing an MRP after the current program expires in 2020?

A. Yes. SEMCO Gas believes that the replacement of facilities that present undue risk is important to the safety of SEMCO Gas's customers, employees, and the general public. SEMCO Gas is proposing to replace 130 miles of MRP qualified pipe from 2021 through 2025 under the MRP for an average replacement of 26 miles per year.

Q. How will SEMCO Gas identify replacement projects to be done under the MRP?

A. Under the MRP, SEMCO Gas will continue targeting unprotected steel and vintage plastic pipe. The Company will continue to utilize the DIMP model for project selection ensuring higher risk pipelines are prioritized for retirement.

Q. Is the Company proposing to continue the base mile requirement under the proposed extended MRP?

A. No. The current MRP requires that SEMCO Gas retire 14.6 miles of MRP qualified main annually under its normal capital program. Under the proposed extended program SEMCO Gas will utilize this funding to replace higher risk facilities that may not include MRP qualified main but presents risk above some MRP qualified main projects. Some of these projects would include retiring, derating, or relocating high pressure and transmission main near population centers, as well as reliability projects.

Q. Please explain Exhibit A-23 (KLS-5).

A. Exhibit A-23 (KLS-5) shows the expected program length and expenditures for replacement of main under the MRP. Lines 7-11 show the proposed extended program spanning from 2021-2025. The first column is the year of the program. The second column is the anticipated amount of Remaining Eligible Main in SEMCO Gas's system, this number is the sum of vintage plastic and unprotected metallic main. As expected, this amount is reduced each year of the program. The third column, the MRP Eligible Main, provides the miles of unprotected metallic and vintage plastic proposed to be replaced each year. The fourth column is the estimated Cost per Mile for the replacement of Eligible Main and related facilities. The fifth column shows the forecasted MRP expenditures for years 2021 through 2025. The sixth column represents the projected Leak Savings associated with MRP.

Q. Please provide a summary of the proposed extended MRP including mileage and spend?

A. Exhibit A-23 (KLS-5) shows that SEMCO Gas is proposing to replace 130 miles of main from 2021 through 2025 for an estimated cost of $59,635,996.

<u>Marquette Connector Pipeline Project</u>

Q. What is the MCP Project?

A. The MCP will interconnect Great Lakes Gas Transmission's ("GLGT") interstate pipeline with SEMCO Gas's Marquette area distribution system and provide a new supply receipt point into Northern Natural Gas's ("NNG") transmission system. The construction of the MCP is vital to address the lack of redundancy and to improve reliability in the Company's U.P. West service area. In addition, the construction of the MCP has the added benefit of increasing deliverability and natural gas supply options. Exhibit A-24 (KLS-6) shows the location of the MCP relative to NNG's and GLGT's pipelines. The Commission authorized the construction and operation of the MCP in its August 23, 2017 Order Approving Settlement Agreement in Case No. U-18202.

Q. Please discuss the estimated cost of the MCP.

A. The estimated cost of the MCP is $159,020,445. As reflected in Exhibit A-12 (KLS-1), Schedule B-5 page 4, the current historical spend (column b) is $6,633,179 and the remaining projected spend (column c) is $152,387,266 for a total estimated spend of $159,020,445. In SEMCO Gas's Act 9 filing under Case No. U-18202, the Company forecasted an estimated cost of $140,372,304.

The primary contributing factor to the increased cost of constructing the MCP is the inflation of contractor costs from the time of filing in December 2016.

Q. Please describe the process that SEMCO Gas used to control the construction costs for the MCP.

A. The Company executed a well-considered and prudent approach to awarding the construction contract. A detailed Request for Proposal ("RFP") was developed with mature prints and detailed work scope and submitted to 12 pre-qualified contractors who all participated in an onsite pre-bid meeting. After evaluation of the response to the RFP the Company held post-bid interviews with 5 contractors and after final negotiations awarded the contractual agreement for construction. The contract was awarded to Price Gregory International because they had experience in these types of projects, presented a sound construction work plan, and were the lowest bidder of the group.

Q. What factors contributed to the increased construction costs from the time of the Act 9 filing to the award of the contract in 2019.

A. The compressed timeline for construction in the Upper Peninsula of Michigan and multitude of pipeline projects taking place throughout the country put upward pressure on the overall construction cost. The latest *Pipeline & Gas Journal* survey based on Energy Web Atlas data, indicates 145,353 miles of pipelines were planned or under construction worldwide at the start of 2019-a 73% increase over survey findings published in January 2017.

Q. What is the current construction schedule?

A. Right of Way clearing began with tree felling in February of 2019 and will be completed by the middle of July 2019. Construction of the 10" Marquette Connector Lateral is scheduled to begin in June 2019, following the removal of current frost law restrictions. Construction of the 20" MCP, the Main Line Valves, the interconnect with GLGT, and the interconnect with NNG are to begin concurrently the beginning of July 2019. The construction of the 6" NNG back feed and the 10" distribution piping is to begin the end of July 2019. The in-service date is planned for fourth quarter of 2019.

Service Valve Replacement Program

Q. Please describe the Company's Service Valve Replacement Program.

A. In Case No. U-16169, SEMCO Gas was authorized to replace approximately 40,000 defective service valves on the SEMCO Gas system. SEMCO Gas experienced failures on service line riser valves purchased and installed in the 1980's and 1990's and subsequently determined that these valves had a defect.

The first known failure occurred when a homeowner turned off the valve on the meter at his home. A fire ensued when the valve core separated from the valve, gas was released and the gas ignited. No one was injured but there was extensive damage to the home. Ten other similar failures have occurred, resulting in the release of gas but no ignition of the gas.

SEMCO Gas had the valves analyzed. The analysis showed that dissimilar metals in the valve and a lack of corrosion protection cause the bearing surfaces to seize. When the valve is actuated in this condition the brass valve core can shear off, be ejected immediately from the valve body and release gas at pressures up to 60 PSIG.

Q. Was SEMCO Gas successful in completing the removal of all defective valves?

A. Yes, over 50,000 defective service valves have been replaced.

SEMCO Gas previously trained all field employees to identify defective valves. During the course of atmospheric survey work employees identified valves in the system that were not included in our original estimate. SEMCO Gas was still able to complete the program in the targeted 5 years with the additional valve replacements. Please see testimony submitted by Witness Vincent for accounting summaries.

Q. Does the Company expect to find more defective valves?

A. Currently there are no known valves within SEMCO Gas's system. However, there is a possibility that additional defective valves may still be discovered. If found, SEMCO Gas would replace them under our normal course of work.

__Environmental MGP__

Q. Please explain Exhibit A-25 (KLS-7), "Environmental Expenditures-MGP's".

A. This exhibit describes the actual environmental expenditures made to investigate and remediate former MGP sites in the time period January 2012 through December 2018. The net amount expended on environmental-related activities in this period was $11,261,486. The net amount spent in each calendar year is amortized over a ten-year period, in accordance with the

Commission's November 7, 1997 order in MPSC Case No. U-11409. I will discuss the work associated with these expenditures and the reasons for including them. This exhibit also shows expected environmental expenditures of $10,000 in 2019 and $0 in 2020.

Q. Why did SEMCO Gas investigate environmental conditions at these MGP sites?

A. SEMCO Gas 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. SEMCO Gas has complied with the applicable Michigan Department of Environment, Great Lakes, and Energy ("EGLE") requirements, which require current landowners to mitigate unacceptable risks to human health from the byproducts of manufactured gas plant operations and to notify the EGLE and adjacent property owners of potential contaminant migration. SEMCO Gas concluded investigating these sites in 2016.

Q. What environmental expenditures in Exhibit A-25 (KLS-7), were incurred in order to meet compliance requirements?

A. The environmental investigation costs listed in Exhibit A-25 (KLS-7), "Environmental Expenditures-MGP's" were incurred in fulfilling compliance requirements associated with Section 20107a of Part 201, the Michigan Natural Resources and Environmental Protection Act ("NREPA"). NREPA requires that SEMCO Gas exercise due care to ensure that existing contamination on a property does not cause unacceptable risks to human health and is not exacerbated. Such measures include evaluating the extent of contamination and taking necessary responsive actions. Due care requirements are not related to the liability for investigation and remediation of the contaminants; they apply to potentially responsible parties and others alike. Section 20107a of NREPA requires that SEMCO Gas do all of the following with respect to hazardous substances at a facility: prevent exacerbation of the existing contamination, prevent unacceptable human exposure, 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 EGLE and others.

Q. In your opinion, are the expenditures listed on Exhibit A-25 (KLS-7), "Environmental Expenditures-MGP's" reasonable and prudent?

A. Yes. These expenditures were made in order to meet existing regulatory compliance requirements.

Q. Please discuss past expenditures outlined in this exhibit for 2012 through 2018.

A. SEMCO Gas developed comprehensive work plans for the former Albion and Battle Creek MGP sites. The goal of these plans was 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 EGLE. These activities were scheduled, planned, and budgeted through the end of 2018. Contractors conducted the field investigations and coordination, providing environmental reports (including environmental due care reports), and managing these projects under the direction of an environmental engineer. The detailed work plan for these activities support 2012 expenditures of $2,322,966, 2013 expenditures of $2,314,005, 2014 expenditures of $5,105,837, 2015 expenditures of $805,818, 2016 expenditures of $680,807, 2017 expenditures of $19,317, and 2018 expenditures of $12,737 for a seven-year total of $11,261,486 in known and measurable expenditures. Please refer to the testimony of Witness Vincent for the annual amortization expense the Company is seeking to recover in this case relating to the environmental expenditures.

Q. Please describe SEMCO Gas's former Marysville MGP site.

A. The Marysville MGP site was operated by DTE Electric Company ("DTE") from approximately 1927 until June of 1950 when it was sold to SEMCO Gas. Historic on site structures included a tar separator, tar storage structures, purifier boxes, oil strainer, oil storage tank, coal conveyor, ash pit, and a commercial gas holder. The Company manufactured gas at the site for a short time, and then used the site as a training center.

Q. Please discuss the current status of the Marysville MGP site.

A. SEMCO Gas no longer owns the site. In 2014, SEMCO Gas transferred the ownership and all liability for the site back to DTE. This was a negotiated settlement in which DTE assumed all actual and potential liability related in anyway whatsoever to the former Marysville MGP operations and demolition and in exchange SEMCO Gas paid DTE Electric Company ("DTE") $1,300,000. This payment represented SEMCO Gas's sole future contribution to the cost of environmental investigation and remediation of the site. Prior site investigations projected expected remediation costs to be above $6 million dollars (2006 value), significantly higher than the $1.3 million settlement amount paid in 2014.

Q. What is the status of SEMCO Gas's MGP sites?

A. Currently all sites are considered closed. The Albion Former MGP Post Closure Agreement between SEMCO Gas and the EGLE was signed, and the No Further Action Letter was issued on August 18, 2015. The Battle Creek Former MGP Post Closure Agreement between SEMCO Gas and the EGLE was signed, and the No Further Action was approved on November 15, 2016.

Q. Please explain future expenditures expected for SEMCO Gas's MGP sites.

A. Exhibit A-25 (KLS-7) identifies an expected expenditure of $10,000 in 2019 for miscellaneous legal expenses related to the former Battle Creek MGP facility and $0 for 2020.

<u>Incremental O&M</u>

Q. Please explain Exhibit A-26 (KLS-8), "Incremental O&M".

A. This exhibit outlines incremental Operation and Maintenance ("O&M") expenses that are projected for 2020. Some of these O&M expenses will be incurred for facilities that were placed in service in 2018 and 2019. The remaining expenses are for programs driven by integrity and reliability projects required for the safe operation of the system.

<u>Infrastructure Reliability Improvement Program</u>

Q. Please describe the event that Consumers Energy experienced on January 30, 2019.

A. On January 30, 2019, a fire occurred at Consumer's Ray Natural Gas Compressor Station in Macomb County. The fire resulted from a fire gate blowdown that was ignited by the adjoining plant's thermal oxidizer. The Ray facility contains about 65% of Consumer's working gas capacity in Michigan. The fire reduced the amount of natural gas availability which forced Consumers to issue a mandatory curtailment of gas deliveries to large business customers and requested all natural gas customers in Michigan to conserve natural gas.

Q. Please describe the assessment conducted after Michigan's Polar Vortex experienced in January, 2019.

A. After the Consumers' infrastructure event, Michigan's Governor Whitmer requested that the MPSC review the supply, engineering, and deliverability of Michigan's natural gas, electricity, and propane in Case No. U-20464. Following this, SEMCO Gas conducted a hazard analysis on its gas system. The impact of abnormal operating conditions on critical stations, pipelines and upstream supply was analyzed to determine potential customer outage vulnerabilities. Mitigation plans were identified to address system vulnerabilities discovered through this analysis. The completion of these mitigation projects will provide reliability and safety for thousands of customers within SEMCO Gas's service territories.

Q. Has SEMCO Gas experienced a supply issue that could have been avoided by having a redundant system in place?

A. On December 13, 2016, Panhandle Eastern was attempting to perform ILI pigging of their lateral pipeline which feeds SEMCO Gas's PEPL #1 gate station in Battle Creek. The pig became stuck at an elbow in the lateral at some point during the run. After exhausting all attempts to dislodge the pig, PEPL decided it needed to excavate and extract the pig by cutting it out of the pipe. Due to planning and preparation, the extraction process was anticipated to take as long as 30 days. Extracting the pig was delayed into the peak heating season for this incident. Fortunately, at this point on SEMCO Gas's Battle Creek system there is a redundant interconnect with ANR Pipeline. Without the redundant interconnect, SEMCO Gas may have had an outage of approximately 20,000 customers by losing the supply point.

Q. Please provide an example of an identified system risk and the resulting mitigation identified through the Company's hazard analysis.

A. A large portion of SEMCO Gas's Eastern District is supplied by a single 10" pipeline. A break on this pipeline or a problem with the district station feeding it would result in a loss of approximately 23,000 customers on a peak day. In addition, the Company would lose supply to a hospital and multiple schools and nursing homes. SEMCO Gas proposes to mitigate this risk by installing 4.3 miles of 10" pipeline to loop the existing pipeline supplying this area. Exhibit A-27 (KLS-9) details additional proposed projects identified to mitigate system reliability issues. SEMCO Gas will reevaluate this list annually and update project plans as hazards change or alternate solutions are identified.

Q. Please describe the specific details of the IRIP SEMCO Gas is proposing in this proceeding?

A. SEMCO Gas is proposing to spend approximately $55 million dollars through 2025 to complete the projects detailed in Exhibit A-27 (KLS-9). Exhibit A-28 (KLS-10) shows the estimated annual spend required to complete these projects in a timely manner and also shows the expected plant to be in service at the conclusion of each year. These projects require a substantial investment in plant that would be beyond the normal capital program and therefore, SEMCO Gas is proposing a method of recovery similar to the MRP. The Company proposes to recover the costs related to these capital expenditures through a surcharge on customer bills until the next general rate proceeding at which time these investments would become part of SEMCO Gas's rate base. Recovery will not start until 2021, in unison with the proposed MRP and the recovery would be on the average spend over the five year program.

Q. How will the Company communicate the status of the Infrastructure Reliability Improvement Program?

A. In order to ensure the MPSC is aware of the status of the work being conducted and the resulting reliability improvements provided to our customers, SEMCO Gas proposes to submit an annual report to outline information pertinent to the program.

Q. Why doesn't the Company do these projects under routine capital work?

A. The costs of completing these projects would deplete the Company's annual capital budget. The Company could complete the projects over multiple years but this approach would add increased costs and delay the benefits proposed. Dan Forsyth further discusses the benefits of this approach in his testimony.

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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas,	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF MARK A. MOSES

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Mark A. Moses
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. My name is Mark A. Moses. My business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

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

A. I am employed by SEMCO Energy, Inc. ("SEMCO") as its Vice President, Chief Financial Officer and Treasurer. I am appearing in the proceeding on behalf of 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 Cedarville University in 1986 with a B.A. in Accounting and Business Administration. I have been employed by SEMCO since 1988. Prior to being named to my current position, I held various positions with increasing levels of responsibility in the finance, corporate development and accounting departments within SEMCO. My years with SEMCO and the various positions that I have held have provided me with a very comprehensive knowledge of SEMCO, its divisions and subsidiaries, and the regulated environment in which SEMCO operates. For example, my responsibilities in the budgeting and financial forecasting areas have provided me the opportunity to interact with SEMCO employees throughout the organization and required me to report the results to SEMCO's Board of Directors. Also, as the lead individual in the Finance area, I have been tasked with ensuring that SEMCO is adequately capitalized and has ample liquidity to meet both long-and short-term requirements.

Q. What are your job responsibilities?

A. In my current role, my primary job responsibilities include: (i) overseeing the preparation of all SEMCO and SEMCO Gas accounting records and systems, including various financial statements and reports prepared from those records; (ii) monitoring SEMCO's borrowings and investments; (iii) ensuring income tax accounting and compliance; (iv) ensuring the filing of regulatory reports; (v) providing guidance in the development of accounting methods and procedures designed to provide adequate internal accounting controls; and (vi) ensuring that SEMCO (including SEMCO Gas) conducts its business in accordance with accounting standards prescribed by the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts and in conformity with

Generally Accepted Accounting Principles ("GAAP"); (vii) overseeing the preparations of financial budgets and forecasts; and (viii) overseeing risk management.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("Commission")?

A. Yes. I provided previous testimony and exhibits in the following cases:

U-16169 – General Rate Case Filing

U-20311 – Application of Determination of Calculation C

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

A. The purpose of my testimony is as follows:

1. describe the legal structure of SEMCO and its relationship to SEMCO Gas;
2. describe the nature of certain shared services SEMCO provides to SEMCO Gas;
3. describe how these services are charged to SEMCO Gas;
4. support the associated costs of those services to SEMCO Gas in satisfaction of the affiliate standards set out in statute, to the extent they apply;
5. describe the methodology for allocating costs charged from AltaGas Ltd. ("AltaGas") to SEMCO for services provided for and on behalf of SEMCO Gas;
6. describe and support the methodology used by SEMCO Gas in this filing to forecast Operations and Maintenance ("O&M") expense and Property and Other Tax expense. These forecasted figures are used to calculate "Projected Test Year Net Operating Income," which is discussed by Dr. Fairchild; and
7. describe and support the methodology used to determine the "Other Gas Revenues" included in the Projected Test Year Net Operating Income.

Q. What exhibits are you sponsoring in this case?

A. I am sponsoring the following exhibits:

Exhibit A-13 (MAM-1), Schedule C-5 (Projected Operation and Maintenance Expenses)

Exhibit A-13 (MAM-2), Schedule C-7 (Projected General Taxes)

Exhibit A-13 (MAM-3), Schedule C-3.1 (Projected Other Gas Revenue)

Q. Were these exhibits prepared by you or under your directions?

A. Yes.

<u>Legal Structure of SEMCO and Its Relationship to SEMCO Gas and Allocation of Shared Service Cost</u>

Q. Please explain the legal structure of SEMCO and its relationship to SEMCO Gas.

A. SEMCO is a regulated public utility company with geographically distinct divisions in both Alaska and Michigan and investments in other energy-related entities. The Alaska division of SEMCO operations is referred as ENSTAR, and the Michigan division of SEMCO operates is referred to as SEMCO Gas. While SEMCO's divisions are organized as distinct parts of SEMCO's business, they are not stand-alone legal entities but a part of SEMCO, which is the legal entity under that the divisions operate. SEMCO's ultimate parent company is AltaGas, a Canadian company.

Q. Are SEMCO and AltaGas "affiliates" under Michigan statute?

A. For purposes of applying the Commission's Guidelines for Transactions between Affiliates, "affiliates" have the same meaning as "associated companies" in the FERC Uniform System of Accounts for gas and electric utilities. In the FERC Uniform System of Accounts, the term "associated companies" means companies or persons that directly or indirectly through one or more intermediaries control or are controlled by, or are under common control with the affiliated company. AltaGas indirectly holds 100% ownership interest in SEMCO Energy, Inc.; and SEMCO Gas is a division of SEMCO Energy, Inc. On this basis, AltaGas and SEMCO are "affiliates." While SEMCO Gas is a division of SEMCO, and not a distinct legal entity or person separate and apart from SEMCO, SEMCO Gas is not an affiliate of SEMCO or AltaGas under the strict definition. However, as I discuss below SEMCO treats the shared services provided by AltaGas and SEMCO to its divisions and subsidiaries in accordance with SEMCO's Affiliated Transaction Policy Manual, which the Commission has previously reviewed.

Q. Can you explain what shared services are provided by SEMCO on behalf of its divisions and subsidiaries?

A. Yes, there are certain functions that are centralized at SEMCO and the cost of those functions are shared by all of SEMCO's divisions and subsidiaries, thereby achieving cost savings for the whole organization. At SEMCO, we refer to these centralized functions as "Shared Services."

Q. Why are these functions performed by SEMCO instead of separately by each of SEMCO's divisions or subsidiaries?

A. By consolidating the performance of Shared Services at SEMCO, which are necessary for all divisions and subsidiaries, SEMCO achieves economies of scale and other efficiencies that could not be achieved by the divisions or subsidiaries, including SEMCO Gas, on a stand-alone basis. The primary savings or cost efficiencies result from the elimination of redundant service groups or providers within the organization. Instead of each division or subsidiary providing the Shared Services (discussed in more detail below) on a stand-alone basis, these functions are provided by SEMCO. This centralization results in a reduction of the total number of employees required to provide these services and allows for greater employee technical expertise, specialization, and work performance. In addition to the benefits and cost savings achieved, consolidation of support services at SEMCO allows SEMCO Gas and other divisions and subsidiaries to focus on achieving operational excellence and providing responsive customer service.

Q. Does SEMCO Gas incur costs associated with SEMCO's provision of these Shared Services?

A. Yes. SEMCO Gas receives an allocation of costs for the Shared Services provided by SEMCO.

Q. What was the total cost of the Shared Services in 2018?

A. The total cost of the Shared Services in 2018, including an amount allocated from AltaGas was $15,507,014. Of this total, $9,650,038 was allocated to the Company based on the cost allocation methodology described later in my testimony.

<u>Description of Shared Services</u>

Q. What types of Shared Services are provided by SEMCO on behalf, or for the benefit, of SEMCO Gas?

A. The Shared Services include certain functions or activities that any viable business needs, or is required to perform. Generally, with companies of SEMCO's size, these required functions can be centralized in order to capture economies of scale and efficiencies resulting in cost savings for the organization. If these functions were not centralized, then each of SEMCO's divisions and subsidiaries would be required individually to perform these functions.

Q. Can you delineate the centralized functions at SEMCO that make up the Shared Services?

A. Yes. The primary centralized functions that make up the Shared Services that SEMCO provides to SEMCO Gas as well as to its other divisions and subsidiaries are:

- Accounting/Tax;

- Corporate Compliance, Communications and Record Maintenance;
- Finance/Treasury;
- Information Technology (“IT”);
- Human Resources (“HR”);
- Risk Management; and
- Facilities.

Each category of service provided by SEMCO to SEMCO Gas is described below.

Q. Please describe the Accounting/Tax services provided to SEMCO Gas.

A. SEMCO prepares, on behalf of all its subsidiaries and divisions, quarterly and annual external consolidated financial reports, which resemble the SEC Form 10-K annual and SEC Form 10-Q quarterly filings, and provides them to lenders and the Commission, among others. SEMCO also prepares and supports the filing of federal, state, and local income tax returns, federal payroll reporting, and federal accounts payable reporting for all of its subsidiaries and divisions. It also reviews and performs analytics on the monthly financial results for all the subsidiaries and divisions and prepares consolidated reports for management. Further accounting services include calculating SEMCO Gas’ asset retirement obligation, benefit plan accounting and compliance reporting, goodwill impairment testing, and income tax accounting. SEMCO also researches new accounting pronouncements and implements corresponding procedural changes. SEMCO coordinates annual internal audits and annual external audits. Finally, SEMCO’s accounting group provides application support for SEMCO Gas’ accounting systems (accounts payable, payroll, fixed assets, general ledger, and financial reporting).

Q. Please describe the Corporate Compliance, Communications and Record Maintenance services provided to SEMCO Gas.

A. This category includes the cost of providing corporate-wide legal services such as corporate management, corporate filings and corporate secretary duties.

Q. Please describe the Finance/Treasury services provided to SEMCO Gas.

A. This corporate function performs the daily cash management on a consolidated basis for the organization, which includes forecasting cash requirements, arranging for short-term borrowings from banks, and processing all wires and ACH payments. It also makes arrangements and coordinates issuance of both short- and long-term debt. In addition, this function coordinates strategic planning and prepares budgets and forecasts of revenue, costs, and profitability on a corporate-wide basis to provide corporate and divisional management the tools to monitor financial performance. Finally, this function prepares material for and interacts with credit rating agencies.

Q. Please describe the IT services provided to SEMCO Gas.

A. SEMCO provides overall support for the IT departments across all SEMCO divisions and subsidiaries. It procures computer server hardware, software licenses and maintenance for the finance and accounting systems used by all SEMCO divisions and subsidiaries. These systems maintain electronic records and related reporting for SEMCO Gas' general ledger, accounts payable, fixed assets, HR, purchasing, inventory, payroll, budgeting and reporting functions. Additionally, the IT function provides cybersecurity activities for SEMCO including its divisions and subsidiaries. Witness Matt Kosht addresses the importance of this critical activity in his direct testimony.

Q. Please describe the HR services provided to SEMCO Gas.

A. SEMCO's HR Shared Services function administers all of the benefit plans for SEMCO's employees, which include both those located in Michigan and Alaska. These plans include pension, 401(k), medical, dental, vision, life insurance, accidental death and dismemberment, long-term disability and flexible spending accounts. Other benefit services performed by the SEMCO HR function on behalf of all SEMCO employees include eligibility tracking, enrollments, terminations, status changes, claim resolution, pension calculations and payment, compliance filings and mailings, audit support, benefit plan document maintenance, benefit plan interpretation, funding, budget development and vendor management. Administration of the compensation programs is also performed by SEMCO's HR function, including annual updates of pay ranges, market pricing of new and changing positions, and participation in national and regional compensation surveys.

Q. Please describe what Risk Management services are provided to SEMCO Gas.

A. This function, performed by SEMCO for all its divisions and subsidiaries, includes identifying, analyzing and evaluating the potential loss exposures to SEMCO. The function also monitors risk control programs/procedures and financial risk transfer programs (i.e., insurance) to mitigate the adverse effects of loss in the most economical way to the organization.

Q. Please describe the Facilities services provided to SEMCO Gas.

A. This function includes the O&M cost associated with SEMCO's facilities utilized by all of the Shared Services personnel in the performance of their functions.

Q. Are there other SEMCO-related costs that are allocated to SEMCO Gas besides the O&M costs associated with the Shares Services functions?

A. Yes. In addition to the O&M costs associated with the Shared Services functions, SEMCO allocates some depreciation and property and other taxes that relate to the Share Services functions. In 2018, the amount of depreciation allocated to SEMCO Gas was $170,424, and the amount related to property and other taxes was $141,994.

Q. Are the Shared Services provided by SEMCO consistent with the services provided by other service companies?

A. Yes. These services are common activities that are inherent in the ongoing management of a utility company and are relevant to more than a single project, division, or subsidiary within SEMCO. The related activities are performed in a centralized manner on behalf of all SEMCO divisions and subsidiaries, thereby achieving economies of scale. In this case, SEMCO operates multiple business units in different states, with various operating characteristics such that these common activities can be shared, thus avoiding duplication within the individual divisions or subsidiaries and maximizing the utilization of resources dedicated to providing these activities across multiple business units.

Q. Has SEMCO consistently provided these Shared Services to SEMCO Gas over time?

A. Yes. SEMCO has consistently provided these Shared Services to SEMCO Gas for more than 30 years.

Q. Are the Shared Services provided by SEMCO necessary?

A. Yes. These Shared Services are common administrative services that are part of managing and operating a utility company. Many of these services focus on good business practices, such as risk management, legal services, budgeting, financial and tax planning, and managing information technology and human resources.

Q. How do the Shared Services provided by SEMCO benefit customers?

A. SEMCO Gas and its customers benefit from the types of Shared Services that SEMCO provides in several ways. SEMCO Gas benefits from having experienced, competent professionals perform the specialized tasks inherent in running any company, including a utility company. By consolidating these Shared Services at SEMCO, SEMCO Gas enjoys the benefits of cost efficiencies that cannot be achieved if it were to source these Shared Services from third parties or replicate these services on its own. Consolidating these services enables cost-sharing so that each division and subsidiary of SEMCO only bears a portion of these costs and allows each division and subsidiary to leverage the experience of the Shared Services employees. This arrangement also allows SEMCO Gas to focus on providing safe and reliable gas utility service to its customers.

Q. Are the Shared Services costs allocated to SEMCO Gas in the public interest?

A. Yes. The Shared Services cost allocated to SEMCO Gas are not only necessary to the operation of SEMCO Gas, the savings that results from the economies of scale derived from the allocated Shared Services cost , due to SEMCO not needing redundant administration functions at each of its divisions, accrue to the benefit of the customers in the form of lower rates.

<u>Cost Allocation and Competitiveness</u>

Q. How are the costs relating to the Shared Services charged to the Company?

A. SEMCO follows an Affiliated Transaction Manual ("ATM") that is regularly audited and submitted to the MPSC for review, as required. The ATM is used to allocate both direct and indirect costs to its divisions and subsidiaries for the services it provides on behalf of, and/or for the benefit of, its divisions and subsidiaries. The term "affiliate" is somewhat of a misnomer when applied to SEMCO Gas since, as previously discussed, SEMCO Gas is in fact a division of SEMCO and not, in the strict sense of the term, an affiliate. However, the methodology delineated in the ATM for allocating costs associated with the Shared Services that are provided by SEMCO has been consistently accepted for many years in both Michigan and Alaska. Attached to my testimony as Exhibit MAM-4 is SEMCO's ATM.

Q. Can you explain the method delineated in the ATM for the allocation of the Shared Services cost to SEMCO Gas?

A. Yes. The ATM delineates a precise method of allocating both direct and indirect charges. To the extent that costs are specifically attributable to SEMCO Gas, those costs are charged directly to SEMCO Gas. For other costs that SEMCO Gas benefits from, but which cannot be directly assigned to the Company, those costs are apportioned using the Modified Massachusetts Formula ("MMF").

Q. Please describe the Modified Massachusetts Formula.

A. The principle behind the MMF is to allocate shared expenses according to each division or subsidiary's relative share or consumption of the parent company's services. The purpose of the MMF is to assign an allocation factor ("MMF Factor") to each individual division or subsidiary, which represents their proportionate share of SEMCO's overall investment, revenue, and employees.

Q. Is this an accepted practice?

A. Yes. The MMF is used by utilities to allocate costs before many state jurisdictions across the country as well as before the Federal Energy Regulatory Commission. The MMF is one of the most commonly used multi-factor formulas approved for use by state and federal regulators.

Q. Does SEMCO charge a mark-up or profit of any kind on the cost it incurs to provide these Shared Services?

A. No. These Shared Services are provided at cost. In other words, costs associated with the Shared Services are allocated to divisions or subsidiaries with no mark-up or profit of any kind.

Q. Can you explain in more detail how the MMF was determined for SEMCO Gas in 2018?

A. Yes. The chart below depicts how the MMF was computed for 2018 for SEMCO Gas. As the chart demonstrates, the Company's proportions of SEMCO's total property, gross margin and payroll are 57.91%, 55.40% and 58.46%, respectively. When weighted equally, SEMCO Gas' portion of the SEMCO share service cost computes to 57.27%.

SEMCO ENERGY INC

2018 MMF ALLOCATION BASIS - Total Sheet

Balances @ 12/31/17	Total	MPSC Gas Co
Property		
Utility Plant (Net of A/D)	729,965,699	451,522,435
Non-Utility Plant (Net)	4,712,050	74,266
Inventories		
Gas in Storage	98,461,048	33,552,131
Materials and Supplies	11,247,833	3,915,350
Total Property	844,386,630	489,064,182
Property Factor	99.98%	57.91%
Payroll		
2017 Wages	54,342,750	30,112,064
Total Payroll (excl indirect)	54,342,750	30,112,064
Payroll Factor	99.99%	55.40%
Gross Margin		
Gross Operating Revenue	638,942,165	275,767,299
Less Cost of Sales/O&M Expense	487,441,237	187,202,296
Total Gross Margin	151,500,928	88,565,003
Gross Margin Factor	100.01%	58.46%
2018 AVERAGE FACTOR	**100.00%**	**57.27%**
2018 AVERAGE FACTOR (1)	**100.00%**	**97.48%**

(1) All Level 1903 and H/R Exps(Level 1904)

Q. What MMF Factor was applied to SEMCO Gas in 2018?

A. The factor applied to the Company in 2018 for most of the Share Service functions was 57.27%, but there are two Share Service levels which were allocated at 97.48% due to the fact that the majority of the activities in those levels are being performed on behalf of the Company.

Q. Please identify the two levels that are allocated at the higher percentage.

A. One of the levels is used to track certain HR benefit costs for employees that work, predominately, for the Company. The other level is Public Affairs, and expenses recorded to this level and are not part of the Company's recoverable O&M expenses.

Q. Is the allocation factor the same ever year?

A. No. The allocation factor does change annually depending on the Company's proportion of SEMCO's total property, payroll and gross margin. For example, the factor the Company is being allocated in 2019 is 59.41%.

Q. Has SEMCO incurred any costs for services that are not allocated to SEMCO Gas?

A. Yes. Some SEMCO Shared Services employees allocate some of their time directly to SEMCO's other division or subsidiaries based on work performed directly for the division or subsidiary. In addition, some of SEMCO Shared Services employees allocated some of their time directly to other AltaGas affiliated companies in 2018. As a result, the amount of the salaries and benefits for some of SEMCO's Shared Services employees allocated through the MMF does not represent the full cost of those employees in 2018. Therefore, SEMCO Gas is not being allocated the full salary and benefit costs associated with some of SEMCO's Shared Services employees.

Q. Has there been any change to SEMCO's allocation methodology since the Company's last general base rate case (case number U-16169)?

A. Yes, there has been one change. The only change that has been made is associated with the allocation methodology used for employee compensation relating to the Short-Term Incentive Plan ("STIP") and Long-Term Incentive Plan ("LTIP") bonuses. Until 2015, all STIP and LTIP compensation for all of SEMCO's employees, including SEMCO Gas employees, was allocated to each of SEMCO's divisions or subsidiary using the MMF. However, in 2015, SEMCO began allocating the STIP and LTIP for each applicable employee directly to the division or subsidiary the employee worked for in 2015 if they were dedicated employees such as the "SEMCO Gas employees" as defined earlier in my testimony. Employees identified as Shared Services employees still have their STIP and LTIP allocated using the MMF. SEMCO believes the direct allocation of STIP and LTIP for employees who are dedicated to certain divisions/subsidiaries better aligns with theories of cost causation. Other than that change, there have been no other material changes to the SEMCO allocation methodology.

Q. What assurance does the Commission have that SEMCO is following the ATM appropriately with regard to intra-company and affiliate allocations?

A. The Commission required SEMCO to conduct an internal audit of its affiliated transactions, which includes transactions to SEMCO Gas, every three years. For more than 20 years SEMCO has triennially filed the internal audit report with the MPSC, most recently on April 25, 2019. These audit reports demonstrate that SEMCO's Shared Service costs are appropriately allocated pursuant to the Commission-approved mechanism as SEMCO's independent auditors concluded in their report filed on April 25, 2019.

Q. Are there other cost controls associated with the services provided by SEMCO to SEMCO Gas?

A. Yes. We use the annual budgeting and weekly forecasting processes as tools to help control spending and hold local managers accountable. As added incentive, employee bonuses are tied, in part, to meeting budgetary goals set by SEMCO which has resulted in SEMCO Gas' O&M increasing on a Compound Average Growth Rate ("CAGR") basis from 2009, its last historical test year, to 2018 by approximately 0.23%. This is significantly below the inflation rate over the same time period, when measured by the Consumers Price Index ("CPI"), which was approximately 1.76% on a compound average basis (source: www.in2013dollars.com/2009-dollars-in-2018). Additionally, internal auditors review controls and perform tests of transactions and balances on a periodic basis. There is also the external auditors' annual review of the books and records of SEMCO and its divisions and subsidiaries. Lastly, SEMCO, as part of a larger publicly traded company, is accountable to its ultimate parent company, AltaGas, in managing and controlling costs.

Q. Are there any other costs allocated to SEMCO Gas?

A. Yes, SEMCO allocates a portion of the costs allocated to it from AltaGas to the Company using the same allocation methodology used to allocate the SEMCO Shared Services costs.

Q. How do the 2018 Shared Services costs, including the portion allocated to the Company from AltaGas, compare to costs allocated from SEMCO to SEMCO Gas since 2009 (the Company's last historical test year)?

A. The costs associated with the Shared Services allocated to SEMCO Gas, including the amount allocated from AltaGas, have increased by less than $300,000 since 2009 (SEMCO Gas' last historical test year) when compared to the 2018 Historical Test Year. While costs have fluctuated since 2009 in the various Shared Service functional areas, the costs allocated to the Company in the aggregate have only increased by approximately $253,000 which represents a percentage increase of approximately 0.30% between 2009 and 2018.

Q. Are the charges associated with the Shared Services allocated to SEMCO Gas, including the amount allocated from AltaGas, competitive with costs that would be incurred if the services were provided by an unaffiliated third party?

A. Yes. The charges for the Shared Services are competitive with costs that would be incurred if the services were performed by an unaffiliated third party. This is demonstrated in several ways.

First, as a member of the AltaGas family of companies, SEMCO follows AltaGas' corporate philosophy of keeping all costs for its entire corporate enterprise at a competitive level with its competitors and peers. SEMCO has obligations not only to its customers through its business units, but to its shareholder, to keep costs associated with all activities to a reasonable level and the provision of Shared Services is just one example of where that obligation applies. All costs for Shared Services are subject to strict budgeting processes and other cost controls that are focused on keeping costs at reasonable levels. Second, a portion of the costs being allocated to SEMCO Gas are being performed by third parties and are competitive by definition. For example, SEMCO retains Gregory J. Schwartz & Co., Inc. to provide financial advice on SEMCO's defined benefit plans and 401(k) plans. A portion of those costs are then allocated to SEMCO Gas. While they are allocated through the invoicing process, they are actual costs billed by third parties.

Third, SEMCO Gas is only receiving a fraction of the costs incurred by SEMCO for the Shared Services as described above. Recognizing that the total amount of costs could potentially be less for an organization the size of SEMCO Gas as compared to an organization the size of SEMCO, a large portion of the cost would be necessary regardless of the size of the company.

Fourth, any services provide by third parties to SEMCO Gas will likely contain profit margins that simply are not assessed by SEMCO. While profit margins may differ depending on the type of service provided, it is fair to say that all services would be provided by third parties at fully loaded costs, plus a profit margin.

For these and other reasons, the cost at which SEMCO Gas receives the Shared Services from SEMCO is competitive with the cost at which such services could be received from a third party, if such services were even available.

Q. Are the Shared Services costs allocated to SEMCO Gas from SEMCO, including costs allocated from AltaGas, reasonable?

A. Yes, in my opinion the costs allocated to the Company are reasonable. As stated earlier in my testimony, consolidation of activities performed at SEMCO for SEMCO Gas, and SEMCO's other entities, achieves economies of scale and other efficiencies that could not be realized on a stand-alone basis.

Projected Test Year O&M

Q. Please explain the methodology the Company used in this filing to forecast the O&M expense included in the calculation of Projected Test Year Net Operating Income.

A. SEMCO Gas started with the 2019 board approved budget data (for the projected year ended December 31, 2019) and adjusted that data for expected inflation and known and measureable changes for the Projected 2020 period.

To be more specific, the forecast for O&M expense was based on the Company's 2019 budgeted total O&M expense of $51,292,002 (see Exhibit A-13 (MAM-1), Schedule C-5, line 9, showing the total 2019 budgeted O&M expense for the Company). This schedule also reflects the 2018 Historical Test Year O&M expense on line 1. The 2019 budgeted total O&M figure was then adjusted for expected known and measureable changes, which I will identify and discuss later in my testimony. These adjustments produced a forecasted O&M expense figure for the 2020 Projected Test Year of $59,695,940 (see Exhibit A-13 (MAM-1), C-5, line 43).

Q. Please put this forecasted O&M expense figure in context.

A. The 2020 Projected O&M expense figure represents an increase of $9,853,386 in the O&M expense from the Company's 2009 Historical Test Year of $49,842,554 (Case No. U-16169, Exhibit A-9, Schedule C-5, Line 1) which represents a CAGR in O&M of approximately 1.65%. I would note that this is lower, when measured by the CPI, than the inflation rate in 2018 of 2.44% and lower than the compound average inflation rate from 2009 to 2018 of 1.76% (source: www.in2013dollars.com/2009-dollars-in-2018). I consider this CAGR to be very reasonable and, in my view, this expected level of growth in O&M expense demonstrates SEMCO Gas's continued commitment and focus on controlling O&M expenses. Customers have benefited, of course, from the Company's effort to control O&M cost increases as demonstrated by the fact that SEMCO Gas has not been in for a general base rate case in almost a decade.

Q. Please discuss the significant known and measurable changes made to the 2019 Budgeted O&M expense data to derive the 2020 forecasted O&M figure.

A. The Company made an adjustment to replace the 2019 budgeted Pension and Retiree Medical expense of $919,662 with the expected 2019 Pension and Retiree Medical expense of $3,188,791, which is based on actuarial calculations completed in January 2019. In addition, the Company removed the net impact of its Value Added Program (Home Serve) from the 2019 budget in the amount of $605,000. The Company has historically treated the net revenue from its Value Added Program ("VAP") as a credit to expense. Since VAP's can now be treated "below-the-line" it was necessary to remove the impact of this item from the Company's 2019 Budgeted O&M.

Q. Were there any other known and measureable adjustments that the Company made to the 2019 Budgeted O&M to arrive at the 2020 Projected O&M Expense?

A. Yes. The Company also adjusted the 2019 Budgeted Uncollectible Expense.

Q. What methodology did the Company use to forecast the Uncollectible Accounts expense in the Projected Test Year?

A. The Company used a five-year average uncollectible expense ratio multiplied by the 2020 projected revenue in place of the 2019 Budgeted Uncollectible Expense.

Q. Why did the Company use the five-year average expense ratio?

A. The Company believes that the five-year average Uncollectible Expense Ratio multiplied by the projected 2020 revenue to reflects a more consistent trend and the Company believes it is a better indicator of what the expense for the Uncollectible Expense is likely to be in the Projected Test Year.

Q. What other known and measurable changes were made to the 2019 board approved Budgeted O&M expense data to derive the 2020 Projected O&M figure?

A.. There are additional cyber security expenses that have been identified and addressed in Witness Kosht's testimony in the amount of $210,536. Since cyber security expenses are part of SEMCO's IT Department a portion of those cost will be allocated to all of SEMCO's divisions and subsidiaries. Therefore, the amount allocated to the Company relating to the incremental cyber security expenses in the 2020 Projected Test Year is $125,079. This represents 59.41% of the incremental cyber security expense of $210,536. The 59.41% allocation represents the Company's allocated percentage based on the 2019 allocated shared service percentage as identified earlier in my testimony. Additionally, Witness Singer addresses the need for some incremental operational expenses in the amount of $843,656 not reflected in the Company's 2019 Budgeted O&M in Exhibit A-26 (Incremental O&M Costs). Lastly, there was an adjustment made for the expected general inflation from 2019 to 2020 of 2.28%. This inflation factor was based on the average of three economic forecasts and is delineated in Exhibit A-13 (MAM-1), Schedule C-5, Footnote (a) beginning on line 46.

<u>Projected Test Year Property and Other Taxes</u>

Q. Explain what method was used to forecast Property and Other Taxes for the Projected Test Year.

A. To forecast Property General Taxes for the 2020 Projected Test Year, the Company began with the 2019 Budgeted General Taxes and adjusted for general inflation as delineated in Exhibit A-13 (MAM-2), Schedule C-7, Footnote (a) beginning on line 22. In addition, the Company made an adjustment for the Kansas property tax which is addressed in Witness McLean's testimony (Exhibit A-52). Lastly, the Company made an adjustment to the 2019 Budgeted General Taxes for the property tax increase resulting from the Company's completion of the MCP project (see Exhibit A-13 (MAM-2), Schedule C-7, Line 12). Making the adjustments for inflation, the Kansas property tax, and the incremental property tax associated with the MCP project resulted in an increase in the General Taxes from the 2019 Budgeted amount of $12,281,972 to the 2020 Projected Property and Other Taxes amount of $16,354,703 (see Exhibit A-13 (MAM-2), Schedule C-7, Line 19). I believe that this is an appropriate way to forecast the 2020 Projected Test Year General Taxes. However, with the financial pressures being experienced by some local taxing authorities, this estimate is potentially lower than the expense the Company might actually experience.

<u>Projected Test Year Other Gas Revenue</u>

Q. Is there another topic that you would like to address?

A. Yes, I would like to discuss the method used to arrive at the Company's forecast of Other Gas Revenue in the Projected Test Year.

Q. Please continue.

A. The Company used the five year average in Other Gas Revenue and adjusted for known and measureable changes to forecast the 2020 Projected Test Year Other Gas Revenue. Using this standard approach the Company determined that there is a decrease in Other Gas Revenue in the Projected 2020 Test Year compared to 2018 Historical Test Year of $3,649,613.

Q. Please delineate the known and measureable changes you made to the five year average Other Gas Revenue.

A. The known and measureable adjustments made to the five year average Other Gas Revenue were:

1. The removal of the five year average for Hang Fee which is addressed in Witness Ownes' testimony and reflected on Exhibit A-13 (MAM-3), Schedule C-3.1, Line 10;
2. The removal of the five year average for the Convenience Fee which is also addressed in Witness Ownes' testimony and reflected on A-13 (MAM-3), Schedule C-3.1, Line 11;
3. The removal of the five year average for the revenue associated with the Company's Energy Waste Reduction Program (A-13 (MAM-3), Schedule C-3.1, Line 12);
4. A reduction for the removal of the one-time construction revenue earned in 2018 relating to the construction of two pipelines for Upper Michigan Energy Resources Corporation ("UMERC") (A-13 (MAM-3), Schedule C-3.1, Line 13).

Offsetting these decreases was an increase for normalized rental income from the Company's Harbor Side Office Facility at 1411 Third Street, Port Huron MI as discussed in Witness Vincent's testimony and shown on Exhibit A-13 (MAM-3), Schedule C-3.1, Line 14.

Q. Does this conclude your 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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF JILLIAN FAN

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Q. Please state your name, business address, and present position.

A. My name is Jillian Fan. My business address is Suite 1700, 355 4th Avenue S.W., Calgary Alberta T2P 0J1, Canada. I am the Director, Regulatory Policy for AltaGas Ltd. ("AltaGas"). 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. ("SEMCO").

Q. Briefly describe your professional experience and educational background.

A. I have been employed with AltaGas since 2008. I hold a Bachelor of Commerce degree (B.Comm.) in Accounting from the University of Calgary. I completed the Chartered Financial Analyst ("CFA") program and the Certified Management Accountants of Alberta ("CMA") professional program. I am an active member of both the CFA Institute and Chartered Professional Accountants of Alberta.

I have 25 years of experience in the energy and finance industries, including 20 years in energy infrastructure financing, investment, and management. I have attached my resume as Attachment A hereto.

Q. Briefly describe your current professional responsibilities.

A. In my current position as Director, Regulatory Policy for AltaGas, my primary responsibilities include providing support in establishing the overall regulatory policy for AltaGas's natural gas utility businesses. I also provide regulatory support for AltaGas's business development activities.

Q. Have you previously testified before any regulatory commission?

A. Yes, I have testified before the Regulatory Commission of Alaska and the Alberta Utilities Commission.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe the relationship of AltaGas to SEMCO and conversely, SEMCO Gas, and the corporate support services provided by AltaGas to SEMCO. I will also address how these services are allocated to SEMCO. Witness Mark Moses will discuss the manner in which a portion of the Corporate Services costs charged by AltaGas to SEMCO is allocated among different divisions or subsidiary companies of SEMCO, including SEMCO Gas.

Q. Are you sponsoring exhibits in this case?

A. Yes, I am sponsoring the following exhibit:

Exhibit A-45 (JF-1) - Organizational Chart of AltaGas, Ltd.

Q. Was the exhibit prepared by you or under your direction?

A. Yes.

Q. Please describe the relationship between AltaGas and SEMCO.

A. AltaGas is an energy infrastructure business with a focus on natural gas midstream, natural gas utilities and power. AltaGas is a public company that is traded on the Toronto Stock Exchange. AltaGas has business operations in Canada and the United States. AltaGas Services (U.S.) Inc. ("ASUS") is AltaGas's holding company in the U.S. and is a wholly owned subsidiary of AltaGas. AltaGas Utility Holdings (U.S.) Inc. ("AUHUS") is a wholly-owned subsidiary of ASUS; AUHUS holds 100% indirect ownership interest in SEMCO. SEMCO Gas is a division of SEMCO. Therefore, AltaGas is the indirect parent company of SEMCO, of which SEMCO Gas is a division.

Q. Aside from SEMCO Gas, does AltaGas own any other natural gas distribution utilities?

A. Yes, through SEMCO, AltaGas owns ENSTAR Natural Gas Company ("ENSTAR") which provides natural gas distribution services in Alaska. Both SEMCO Gas and ENSTAR are divisions of SEMCO. In addition, through its ownership of AUHUS, AltaGas also indirectly owns Washington Gas Light Company ("Washington Gas"), which provides natural gas distribution services in the District of Columbia ("D.C."), Maryland and Virginia. Washington Gas is a wholly owned subsidiary of WGL Holdings, which was acquired by AltaGas in July 2018. The organization of these natural gas utilities and their holding companies is shown in the AltaGas corporate structure provided in Exhibit A-45 (JF-1).

Q. Are AltaGas and SEMCO "affiliates"?

A. Yes. For purposes of applying the Michigan Public Service Commission ("Commission") MPSC Guidelines for Transactions between Affiliates, "affiliates" have the same meaning as "associated companies" in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts for gas and electric utilities. In the FERC Uniform System of Accounts, the term "associated companies" means companies or persons that directly or indirectly through one or more intermediaries control or are controlled by, or are under common control with the accounting company. AltaGas indirectly holds 100% ownership interest in SEMCO and SEMCO Gas is a division of SEMCO. On this basis, AltaGas and SEMCO Gas are affiliates.

Q. During the test year, did SEMCO receive services from an affiliated service provider?

A. Yes, SEMCO relied on AltaGas to provide support for SEMCO's overall operations during the test year. These services have been provided since 2012, when AltaGas purchased SEMCO. These corporate support services ("Corporate Services") are provided pursuant to written services agreements between ASUS and AltaGas, and between SEMCO, AUHUS and ASUS.

Q. Why are these activities performed by AltaGas?

A. By centralizing these Corporate Services, AltaGas is able to share overhead costs and specific expertise across its businesses and achieve economies of scale and other efficiencies that could not be achieved by its business units or subsidiaries on a stand-alone basis. This centralization also allows for improved employee technical expertise, specialization, work performance, and scheduling. In many cases, AltaGas employees have worked for, or served, utility and energy sector companies for decades and are highly knowledgeable and experienced in industry processes. SEMCO, its divisions and correspondingly the customers benefit from not only deep experience, but a broader industry perspective at a lower cost. In addition, consolidation of Corporate Services allows AltaGas to optimize the performance of its business units and subsidiaries because they can avoid redundant services and focus on achieving operational excellence and providing safe, reliable, and responsive services to their customers. Furthermore, some of these Corporate Services simply cannot reasonably be outsourced by SEMCO to third parties, such as services provided by AltaGas's Board of Directors and its executive management team and officers.

Q. Does SEMCO incur costs associated with the Corporate Services provided by AltaGas?

A. Yes. Pursuant to the service agreements described above, SEMCO is periodically invoiced for its allocated portion of the costs incurred by AltaGas to perform the various Corporate Services.

Q. What types of Corporate Services are provided by AltaGas on behalf, or for the benefit, of SEMCO?

A. AltaGas has three business segments including gas midstream, utilities and power to which it provides Corporate Services. The Corporate Services AltaGas provides to its businesses, including SEMCO, are generally strategic in nature and focus on business oversight, development of and exercise of corporate governance, and ensuring SEMCO has appropriate access to capital. The types of Corporate Services are described below.

Q. What Corporate Services are provided by the AltaGas Board of Directors for the benefit of SEMCO?

A. The AltaGas Board of Directors (the "Board") is ultimately responsible for the stewardship of AltaGas and all of its business units and subsidiaries, including SEMCO. The Board oversees the business affairs of AltaGas and through periodic review of the strategic environment with management, is responsible for developing the strategic direction of AltaGas. The Board ensures the operations of AltaGas meet a high standard of governance, approves AltaGas's consolidated financial statements and quarterly and annual securities disclosure submissions. It also appoints its Chief Executive Officer and other senior officers, and engages in succession planning. The Board also reviews and monitors principal business risks.

Q. Please describe the activities performed by the Executive Committee.

A. The AltaGas Executive Committee provides strategic management oversight to ensure corporate goals and objectives are met for all AltaGas business units. The Executive Committee provides strategic direction on matters including financial planning, capital access, business and capital risk management and organization structure, to achieve corporate objectives. It establishes effective company-wide governance models, internal control standards and procedures to drive efficiencies and cost effectiveness, formulates strategy and provides guidance to operational leadership to optimize AltaGas's lines of business. The executive management team also serves as the principal corporate representatives and spokespersons of AltaGas.

Q. Please describe the Corporate Services provided for SEMCO by the Finance group.

A. The services provided by the Finance group include those associated with treasury, insurance services, commodity and credit risk management, and investor relations and communications. The Finance group is charged with managing equity and debt financing for AltaGas, maintaining AltaGas's capital structure, providing consolidated cash flow forecasts and liquidity management, and monitoring financial market intelligence. The Finance group implements risk management strategies developed by the Executive Committee and approved by the Board. Furthermore, the Finance group is responsible for investor relations and corporate communications activities, including managing analyst, investor, and shareholder communications, managing public and media relations, coordinating AltaGas's annual general meeting and quarterly conference calls, and preparing press releases and investor presentation materials.

Q. Please describe the Accounting and Tax services provided to SEMCO.

A. The Accounting and Tax group prepares monthly, quarterly, and annual consolidated financial statements, and coordinates with external auditors for annual audit and quarterly reviews of AltaGas's consolidated financial statements. This group is also responsible for the payroll function, and assists in the preparation of the analysis of financial information as well as management discussion and analysis that accompanies quarterly and annual consolidated financial statements required for securities filing documents. To satisfy securities disclosure requirements as a public issuer, the Accounting and Tax group implements and maintains the framework for strong internal controls and procedures. In addition, this group assists AltaGas's business units in their annual planning and budget cycle and ensures that business units forecasts are incorporated in strategic planning. The Accounting and Tax group is also responsible for the overall tax compliance and tax planning framework for AltaGas and its subsidiaries. It provides strategic tax perspectives into AltaGas's annual budgeting and strategic planning process, coordinates corporate tax audits, and develops and implements cross-border transfer pricing policies.

Q. Please describe the Corporate Services provided to SEMCO by the Legal and Compliance group.

A. The Legal and Compliance group provides legal service and advice to AltaGas's various business functions. It maintains regular communications with these business functions to ensure effective management of legal matters, including management of external legal counsel where appropriate. It also maintains enterprise risk management framework, develops the annual internal audit plan to examine, evaluate, and report on the adequacy, effectiveness, and efficiency of the systems of internal controls across AltaGas operations.

Q. Please describe the Information Technology ("IT"), Enterprise Resource Planning ("ERP"), provided to SEMCO.

A. The IT group develops and maintains the organization wide IT strategy, standardization, policies, and practices to ensure there is a common framework for compliance and business automation across AltaGas and its subsidiaries. The compliance framework includes policies and practices to ensure access to the company's information assets are safeguarded. The IT group also develops and implements company-wide cybersecurity policies and procedures, as well as heading the enterprise cybersecurity governance committee. Initiatives include an awareness program which provides employees with education, training, support and tools to encourage best practices for cybersecurity. It also conducts 3rd party vulnerability and cybersecurity tests, oversees corporate threat detection and develop incident response protocols.

Q. Please describe the Procurement services provided to SEMCO.

A. AltaGas establishes company-wide strategic procurement procedures and practices to effectively secure supply of goods and services with quality vendors, mitigate commercial risks, and utilize procurement strategies to drive competitive tension and reduce price. This group facilitates active collaboration among procurement leaders from across the organization on procurement activities where possible to leverage enterprise spend opportunities to realize more favorable terms and conditions.

Q. Are these services provided by AltaGas specifically for, or directly to, SEMCO?

A. No. AltaGas performs these services for the benefit of all its business units, which includes SEMCO. These are common services that AltaGas performs as a publicly traded organization for, and on behalf of, all its business units.

Q. Are the services provided by AltaGas consistent with the services provided by other similar service companies?

A. Yes. The services are common and necessary activities that are required as part of the ongoing management of a publicly traded organization and are relevant to more than a single operating entity within the AltaGas corporate family. The related activities are performed in a centralized manner on behalf of all AltaGas operating entities, thus achieving economies of scale. In this case, AltaGas operates multiple business units across the energy industry with various operating characteristics such that these common activities can be shared, thus avoiding duplication within the individual operating entities and maximizing the utilization of resources dedicated to provide these activities across multiple business units.

Q. Is there any duplication of services provided by AltaGas?

A. No. There is no duplication in services or activities performed at the AltaGas level as compared with those performed at the SEMCO level for SEMCO Gas as described in Mr. Moses's direct testimony, SEMCO performs certain "Shared Services" associated with various functions such as accounting, human resources, IT, and finance, for its gas distribution activities in Michigan and Alaska divisions. Although these Shared Services have similar names as the Corporate Services provided by AltaGas, the nature and purpose of the SEMCO Shared Services are different than the Corporate Services performed by AltaGas, in the sense that the SEMCO Shared Services are more focused on the everyday administration and operations of SEMCO Gas, ensuring good business practices. On the other hand, the Corporate Services performed by AltaGas focus on corporate governance, management oversight, strategic advice, guidance and leadership, and providing capital access. The AltaGas Corporate Services are therefore complementary to SEMCO's Shared Services.

Q. Are the Corporate Services provided by AltaGas necessary and provide a benefit?

A. Yes. The services are common activities that are required as part of the ongoing management of a diversified, publicly-traded company. Many of these services are focused directly on corporate governance, legal mandates, regulatory compliance, and reducing financial, operational, and other types of risk. The remaining services are focused on management control, strategic planning, and operational execution.

Further, SEMCO has the benefit of access to energy infrastructure management experience and expertise across the entire organization.

In addition,AltaGas has well-established track record in capital market issuances, access to bank credit facilities and the equity capital market. SEMCO can rely on AltaGas as, and when, it requires capital to deliver safe and reliable gas utility services. The various Corporate Services performed by AltaGas, as described above, are necessary to maintain AltaGas's status as a publicly traded company and to support its continual access to capital markets.

Q. How are the costs of the Corporate Services allocated by AltaGas?

A. AltaGas allocates costs for Corporate Services to SEMCO, based on the Modified Massachusetts Formula ("MMF").

Q. How are Corporate Service costs allocated to SEMCO Gas?

A. As addressed by Witness Moses, SEMCO Gas receives an allocation of these costs through SEMCO.

Q. Does AltaGas charge a mark-up or profit of any kind on the cost it incurs to provide these Corporate Services?

A. No. These Corporate Services are provided at cost. In other words, costs associated with the Corporate Services are allocated to business units with no mark-up or profit of any kind.

Q. What were the allocated costs of the Corporate Services from AltaGas to SEMCO Gas in 2018?

A. The AltaGas corporate allocation to SEMCO Gas was $4.5 million in 2018.

Q. Has AltaGas incurred any costs for services that are not allocated to SEMCO?

A. Yes. Costs incurred by AltaGas solely for its gas or power businesses, corporate and business development costs, corporate donation and promotion, supplemental executive retirement plan expense, share-based incentive compensation expenses, and certain travel expenses are not allocated to SEMCO. These costs are carved out from Corporate Services cost pool as they are generally perceived to be not necessary for utility operations.

Q. Are the charges associated with the Corporate Services provided by AltaGas to SEMCO competitive with costs that would be incurred if the services were provided by an unaffiliated third-party?

A. Yes. The charges for the Corporate Services are competitive with costs that would be incurred if the services were performed by an unaffiliated third-party. This is demonstrated in several ways.

First, the AltaGas corporate philosophy is to keep all costs for its entire corporate enterprise at a competitive level with its competitors and peers. AltaGas has obligations not only to its customers through its business units, but to its shareholders, to keep costs associated with all activities to a reasonable level and provision of Corporate Services is just one example of where that obligation applies. For example, all costs for Corporate Services are subject to strict budgeting and cost controls that are focused on keeping costs at reasonable levels as discussed above. As another example, the AltaGas hiring practices are designed to competitively compensate employees performing services, but are not designed to compensate employees above and beyond what market forces establish as fair and reasonable. The objective of AltaGas's compensation program is to offer competitive base salary compensation at approximately the median among its peer group.

Second, a large portion of the costs being allocated to SEMCO (approximately 46%) are associated with services performed by third parties and are competitive by definition. For example, during 2018, AltaGas retained Ernst & Young for auditing and other consulting work. Ernst & Young provides these types of services in a very competitive market and was retained at arm's length. The amount paid to Ernst &

Young was approximately $3.2 million. A portion of these costs were charged to SEMCO. While the Ernst & Young costs are allocated, they are actually costs billed by third-parties.

Third, SEMCO is only receiving a fraction of the costs incurred by AltaGas for the Corporate Services. While the total amount of costs may be less for an organization the size of SEMCO as compared to an organization the size of AltaGas, a large portion of the costs would be necessary regardless of the size of the company. For example, AltaGas incurred close to $1 million in 2018 for securities listing registration, annual report preparation, annual general meetings, other forms of shareholder communications, and corporate insurance. SEMCO's allocation of these costs was approximately $0.16 million. If SEMCO were to self-provide these services, it would expect to pay approximately $0.85 million, as some of these costs have no direct correlation to company size.

Also for example, a publicly traded company needs a board of directors. These compensation costs alone amounted to approximately $1.6 million for AltaGas in 2018. For illustrative purposes, this figure compares favorably to the average cost of a board of directors of two other Michigan utilities (namely, DTE Energy and Consumers Energy). The average cost for the board of directors for those entities in 2018 was approximately $2.8 million. Also note that while the amount varies from company by company, between 45% and 50% of these amounts were share-based compensation that AltaGas excludes from the cost allocation to SEMCO. On the other hand, SEMCO was only allocated just over $0.1 million of the costs associated with AltaGas's Board in 2018. If SEMCO were to recruit its own board of directors, however, not only will it need to incur the entire amount of board of directors fees on its own, it would also need to provide compensation consistent with customary market practice, which typically includes a share-based compensation component.

Fourth, any services provided by third-parties to SEMCO will likely contain profit margins that simply are not assessed by AltaGas. While profit margins may differ depending on the type of service provided, it is fair to say that all services would be provided by third-parties at fully loaded costs, plus a profit margin. For these, and other reasons, the cost at which SEMCO receives the Corporate Services from AltaGas are competitive with the cost at which such services could be received from a third party, if such services were even available.

Q. Are the Corporate Services provided by AltaGas to SEMCO, and the costs associated with those services reasonable and necessary?

A. Yes. The Corporate Services are necessary, not duplicative of other services provided to SEMCO, are beneficial to customers, and are in the public interest. Furthermore, the costs associated with the Corporate Services are allocated using a widely-accepted methodology, are less than they would be if SEMCO performed the services for itself, and are competitive with what they would be if the Corporate Services were provided by an unaffiliated third-party, if they could be obtained externally. For these reasons, the costs are reasonable.

Q. How does AltaGas demonstrate its stewardship and governance of SEMCO?

A. In May 2012, the MPSC approved the settlement agreement regarding the change of control of SEMCO Gas resulting from AltaGas's acquisition of SEMCO (*reference MPSC docket U-16969*). The MPSC's final order and the settlement agreement included a number of commitments to protect SEMCO Gas and its customers. Over the years, AltaGas has steadfastly comply with all the commitments.

Delivering safe and reliable energy to customers is a top priority focus of AltaGas. Since acquiring SEMCO in 2012, AltaGas has been supportive of SEMCO Gas to continuously improve safety and reliability. This is evidenced by AltaGas's support of SEMCO Gas's proposal to double the dollars spent and double the amount of pipes replaced in SEMCO Gas's Main Replacement Program ("MRP") since it was first approved in 2011. The acceleration of the MRP has enabled SEMCO Gas to complete its MRP nine years sooner than originally intended.

AltaGas also stands by SEMCO Gas's focus to provide premium energy service to its customers. Since the acquisition by AltaGas, SEMCO Gas's customer satisfaction ratings have consistently improved and have been maintained at a high level as shown in the table below.

Customer Satisfaction Survey
Annual Performance 2010-2018

2010	2011	2012	2013	2014	2015	2016	2017	2018
4.38	4.40	4.43	4.52	4.51	4.60	4.70	4.70	4.73

Survey is based on a five point scale

Since AltaGas's purchase in 2012, SEMCO has continued to be a leader in safety and customer service as evidenced by recognition within the industry. SEMCO Gas has been a recipient of AGA's "Industry Leader Accident Prevention" award for its safety performance in 2018 and SEMCO Gas has received this award in 8 of the last 11 years. In 2018, SEMCO Gas also experienced a below average reportable vehicle accident rate as reported in AGA's annual report. In June of 2018, SEMCO Gas was featured in an article outlining gas utilities that had a track record of quick and reliable response to emergency calls. SEMCO Gas also continues, with AltaGas's support, to maintain a low back log of active leaks.

Since 2012, SEMCO Gas accomplished these achievements under AltaGas stewardship and during that time has not sought an increase in its general rates. Of course, a lot of the credit must go to SEMCO Gas's management in constantly improving service quality and operational safety, while doing an excellent job in cost management. The backing of AltaGas nonetheless is also pivotal to SEMCO Gas's success.

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

A. Yes it does.

Jillian Fan

EMPLOYMENT

AltaGas Ltd. 2013-Present

- Director Regulatory Policy

AltaGas Utility Group Inc. 2008-2012

- Director Strategic Development

Brookfield Asset Management 2005-2008

- Vice President

Darby Asia Investors Limited 1999-2004

- Vice President
- Associate

CIBC World Markets 1997-1999

- Associate

Canadian Imperial Bank of Commerce 1996-1997

- Financial Analyst

Numac Energy Inc. 1993-1996

- Treasury Analyst
- Financial Accountant

EDUCATION

University of Calgary: Bachelor of Commerce (distinction), Accounting, 1993
Certified Management Accountant / Chartered Professional Accountants of Alberta, 1996
CFA Institute, 1999

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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF TRACY L. VINCENT

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Tracy L. Vincent
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. My name is Tracy L. Vincent. My business address is 1411 Third Street, Suite A, Port Huron, Michigan 48060.

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

A. I am the Controller of SEMCO Energy, Inc. ("SEMCO"). I am appearing in the proceeding on behalf of SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO.

Q. Please describe your educational background and business experience.

A, I graduated with a Bachelor's of Arts Degree in Accounting from Michigan State University's Eli Broad College of Business. I have been employed at SEMCO since 1997. I began with SEMCO as a financial reporting analyst, moved into budgeting, participated in the implementation of the current accounting software and financial reporting systems utilized by the Company, lead the Sarbanes-Oxley compliance project bringing internal audit back in house, held the position of accounting manager, then director of financial reporting, and I have been in my current position as Controller since October, 2014. Prior to joining SEMCO, I was a Certified Public Accountant in public practice.

Q. What are your job responsibilities?

A. In my current role, my primary responsibilities include: overseeing the preparation of SEMCO's accounting records and systems including the numerous reports prepared based upon those records; directing the income tax accounting and compliance area; developing accounting methods and procedures designed to provide adequate internal accounting controls; and ensuring that SEMCO (including SEMCO Gas) conducts its business in conformity with Generally Accepted Accounting Principles ("GAAP") and as prescribed by the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("Commission")?

A. Yes. I caused to have filed testimony in Case No. U-18452, which established new depreciation rates for SEMCO Gas effective 2019.

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

A. The purpose of my testimony is as follows:

1. Support the depreciation rates used to compute expense for the projected test year;
2. Propose an amortization and recovery period for the costs accumulated in the deferred riser valve account for which deferred accounting treatments was provided in Case No. U-16169;
3. Discuss the remaining amortization amounts as it relates to manufactured gas plant costs that are accumulated in a deferred regulatory asset account;
4. Discuss the cost allocation methodology among occupants as it relates to the SEMCO Gas headquarters buildings, which was purchased in 2018; and
5. Discuss recent changes in GAAP and the impact on SEMCO Gas's accounting records;

Q. What exhibits are you sponsoring in this case?

A. I am sponsoring the following exhibits:

Exhibit A-29 (TLV-1), Depreciation Rates

Exhibit A-30 (TLV-2), Schedule of Remaining Amortization

Q. Were these exhibits prepared by you or under your directions?

A. Yes.

<u>Depreciation Expense</u>

Q. What depreciation rates were used to compute depreciation for the projected test year?

A. The rates used to compute deprecation in the projected test year were the rates approved by the Commission on May 17, 2018, in Case No. U-18452. Exhibit A-29, reflects the depreciation rates approved in Case No. U-18452.

<u>Riser Value Amortization Period</u>

Q. What is the status of the riser value replacement program for which regulatory accounting was approved in Case No. U-16169?

A. The riser values determined to be defective have been replaced as noted in the testimony of Witness, Katie Singer. As such, it is being proposed that the costs of $4,881,117 accumulated during the years 2007 through 2018 to replace these valves be amortized and recovered in rates over three years as part of this proceeding. On an annual basis, the Company is requesting to amortize $1,627,039 per year to account 407.3 Regulatory Debits.

<u>Manufactured Gas Plant Cost Amortization</u>

Q. How does SEMCO Gas account for its environmental costs as incurred at former manufactured gas plant sites?

A. In accordance with a Commission accounting order, the Company maintains the costs for each year in a specific deferred asset account (Account 186) and begins to amortize those costs at the start of the following year over ten years. The amortization remaining as of December 31, 2018, was $8,768,952. The amortization schedule for those costs can be found in Exhibit A-30. This schedule includes an estimate of $10,000 for 2019 forecasted expenditures based upon the testimony of Witness Singer. Ms. Singer also notes that she expects the remediation will be completed during 2019 and no further deferred of costs will be necessary thereafter.

<u>SEMCO Gas Headquarter Cost Allocations</u>

Q. As a result of the Company's 2018 acquisition of the Harborside Office Building ("Building"), where the Company has had its headquarters located in since 2004, what methodology does the Company use to recover or charge the costs to the other occupants of the building?

A. SEMCO Gas shares the Building with SEMCO and other non-affiliated tenants. Shared operations and maintenance costs for the Building are isolated in a specific cost center. At each month-end, the costs in that shared cost center are allocated to a SEMCO cost center based upon the square footage occupied by SEMCO in the Building. The SEMCO cost center is then allocated between SEMCO and SEMCO Gas based upon the square footage occupied by each within the SEMCO utilized space. The non-affiliate tenants pay rent based upon lease terms which were negotiated by the former owner of the Building and assigned to the Company at the time of the Building's purchase. This income is recorded in the account 493 Lease Revenue.

<u>Impact of Adoption of Recent GAAP Changes</u>

Q. Have there been any recent changes to GAAP that have impacted SEMCO Gas and the way it accounts for certain transactions?

A. Yes, there has been. Beginning in January of 2019, a significant change has been required in the way leases are accounting for from a lessee's perspective. As a result of this revised GAAP accounting standard, many leases deemed to have been operating leases under past guidance are now essentially treated similarly to a capital lease under FERC accounting. For leases deemed as finance leases, the leased asset will be recorded on the balance sheet as a Right-of-Use ("ROU") asset in property, plant and equipment with an offsetting liability in debt separated between the current and long-term portion. For leases deemed as operating leases, the leased asset will be recorded on the balance sheet as a ROU asset in deferred debits with an offsetting operating lease liability separated between both current and long-term liabilities. When payments are made on the leases, the payment will be applied to reduce the liability and in the case of finance leases, also record an interest expense component. Finance lease ROU assets are depreciated while the operating lease ROU assets are amortized on a straight-line basis to expense accounts. Under former lease accounting standards, the lease payments on operating leases would have been applied to an expense account or allocated as a component of construction costs that would eventually be included in property balances. However, FERC did not update its definition of a capital lease in its December 27, 2018, response to inquiries surrounding the accounting and financial reporting for leases so there is now a divergence between the treatment of leases for GAAP reporting purposes and regulatory accounting purposes.

SEMCO Gas leases nearly all its vehicles as well as many facilities throughout the state and certain office equipment. In order to remain in compliance with FERC accounting as proscribed in the FERC's memo dated December 27, 2018, the Company is planning to maintain separate accounts for the ROU assets which will be reported in Account 101.1 property under capital leases while the obligations associated with the ROU assets will reported in Account 243 obligations under capital leases - current and Account 227 obligations under capital leases - noncurrent for regulatory reporting on the balance sheet. The depreciation and interest costs relating to the finance lease ROU assets will be recorded to Account 881 rent expense for regulatory reporting on the income statement.

The Company also adopted the new revenue recognition and the presentation changes to net periodic pension and postretirement benefit cost on January 1, 2018. The revenue standard did not change the way that revenue is reported for regulatory purposes and only changed the presentation of disaggregated revenue in the Company's GAAP financial statements. The net periodic pension and postretirement benefit cost presentation change required employers to report the service cost component of net benefit costs in the same line item on the income statement as other employee compensation costs, while presenting the other cost components separately outside of operating income. This reclassification is only presented on the Company's GAAP financial statements and all pension and postretirement benefit cost continue to be reported in Account 926 for regulatory purposes.

Q. Does this conclude your 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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF ANN L. FORSTER

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Ann L. Forster
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. Ann L. Forster, 1411 Third Street, Suite A, Port Huron Michigan 48060.

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

A. I am employed by SEMCO Energy, Inc. ("SEMCO") as the Vice President of Administrative Services. SEMCO Energy Gas Company ("SEMCO Gas" or the "Company") is a division of SEMCO and participates in its compensation plans.

Q. Please describe your educational background and business experience.

A. I received a Bachelor's Degree in Business Administration from Lake Superior State University (1986) and a Master's Degree in Business Administration from Central Michigan University (1991). I began my professional career with Peoples Bank of Port Huron (currently CHASE) in 1986, primarily within the audit function. I was hired by SEMCO into Internal Audit in June of 1989. When Internal Audit was outsourced, I left SEMCO in 1995 and returned in February of 1997 into the Human Resources department, eventually assuming responsibility for the operations of the department. I assumed additional responsibility for oversight of the legal function in 2015, and Customer Service in 2019. I have held the following positions at SEMCO: Internal Auditor, Sr. Internal Auditor, Benefits Administrator, Benefits Manager, Director of Human Resources, Vice President of Employee Services, Vice President of Employee and Legal Services and Vice President of Administrative Services.

Q. What are your responsibilities as Vice President of AdministrativeServices?

A. I have overall responsibility for all human resources,legal and customer service policies, affairs and other matters involving SEMCO.

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

A. The purpose of my testimony is to:

i) explain SEMCO's compensation philosophy;

ii) describe SEMCO's incentive plan design; and

iii) address how SEMCO Gas's customers benefit from SEMCO's incentive plans and why these compensation expenses should be eligible for rate recovery..

Q. What exhibits are you sponsoring in this case?

A. I am sponsoring the following exhibits:

Exhibit A-42 (ALF-1): 2018 Short-Term Incentive Plan, SEMCO Energy Gas Company – Individual Performance Appraisal Key Metric “General Guideline

Exhibit A-43(ALF-2): 2018 – 2020 Long-Term Incentive Plan, SEMCO Energy Gas Company, 3-Year Cumulative Performance Metrics

Exhibit A-44 (ALF-3): SEMCO Energy Gas Company – 2019 General Rate Case Compensation Study

Q. Were these exhibits prepared by you or under your directions?

A. Yes.

I. <u>COMPENSATION PHILOSOPHY</u>

Q. Describe SEMCO’s compensation philosophy.

A. SEMCO’s compensation philosophy is to pay employees “Total Compensation” at the 50th percentile of “market consensus”, or what is commonly known as the “middle of the market”. The Company does this in order to attract, retain, motivate, and reward SEMCO Gas employees to operate the natural gas delivery system in a safe, reliable and efficient manner for the benefit of the Company’s customers.

Q. Does SEMCO’s compensation philosophy apply to the management and professional employees who are eligible for incentive-based compensation?

A. Yes. For simplicity’s sake, in the remainder of my testimony I will discuss how this compensation philosophy applies to management and professional personnel.

Q. How does SEMCO put this compensation philosophy into practice?

A. Businesses of all kinds, including utilities such as SEMCO Gas, routinely participate in wage surveys compiled by compensation and industry organizations for the purpose of defining “market competitive” compensation. The compensation data available from these surveys is used by SEMCO to develop compensation programs that are market driven, serve to attract and retain skilled and qualified personnel, are compliant with equal pay and other discrimination laws, and are defendable in rate case proceedings, such as this. Compensation data is segmented to ensure relevancy to SEMCO by using data cuts such as industry, region, company size, revenue and employee headcount, when available. SEMCO uses the results of this analysis to determine the level of market competitive total compensation it should pay to compete with other employers for talent.

Q. Please describe the compensation components at SEMCO.

A. SEMCO uses three separate compensation components that, when combined, produce "middle of the market" compensation for eligible SEMCO employees. First, base pay is the cash compensation employees receive in their bi-weekly paychecks. Second, the Short-Term Incentive Plan (or "STIP") is intended to compensate eligible employees for the achievement of annual Company and individual objectives. Third, the Long-Term Incentive Plan (or "LTIP") is intended to foster balanced decision making, by compensating eligible employees for the achievement of longer-term objectives. That way, employees will not sacrifice long-term objectives to attain annual (short-term) objectives and related incentive awards. The STIP and LTIP are variable components of an eligible employee's complete compensation package.

Q. How does SEMCO's base pay compensation compare to the market?

A. The SEMCO's base pay compensation for its professional and management employees currently sits below the 50th percentile of the market. The test for determining whether employees are paid base pay at "middle of the market" levels relies on what is called a "compa-ratio". The compa-ratio measures the relationship between actual base compensation and, in this case, the "middle of the market" target base pay derived from the analysis previously described. As of November 1, 2018, the base pay compa-ratio for SEMCO's professional and management personnel is 97%. A compa-ratio of 100% would indicate alignment with the 50th percentile of the market. A compa-ratio of 97% indicates compensation paid below the 50th percentile of the market.

Q. Does this mean that every management and professional employee is paid precisely at a 97% base pay compa-ratio?

A. No. This figure is an average. Some SEMCO professional and management employees are paid less than 97% and other employees are paid more than 97%. Factors such as performance, time with the Company, education and relevant work experience are considered in determining how an employee is compensated within their pay range. Performance is evaluated twice a year and annual performance evaluations are the basis for salary increases.

Q. Does the compa-ratio described above apply to both base pay and incentive compensation?

A. No. The 97% compa-ratio described above applies to just the base pay portion of an employee's total compensation package with SEMCO.

Q. Is incentive compensation part of the "middle of the market" approach SEMCO takes to total compensation?

A. Yes. Incentive compensation is a key component of SEMCO's total compensation philosophy. Without incentive compensation, SEMCO would be offering a total compensation package significantly below the "middle of the market", seriously impacting its ability to attract and retain qualified employees.

Q. Do SEMCO personnel benchmark and calculate the base pay components for all non-union employees?

A. No. While the SEMCO Human Resources staff prepares the annual base pay ranges for most of its non-union employees, the SEMCO uses Willis Towers Watson ("WTW") to calculate executive base pay and to evaluate incentive compensation compared to benchmarks. This study by WTW is performed every two to three years. In the years the study is not conducted executive base pay ranges are rolled forward using available survey data related to classification movement.

Q. Through its studies, has WTW found that SEMCO's executive pay components are reasonable compared to the utility industry?

A. Yes. Please see Exhibit 42 (ALF-3), SEMCO Energy Gas Company – 2019 General Rate Case Compensation Study conducted by WTW.

Q. Does SEMCO's approach to developing its compensation programs support your view that incentive compensation is a valid component of total compensation?

A. Yes. Data shown in most comprehensive compensation surveys consistently make it clear that there are several standard elements of utility management and professional employee compensation. As a result, SEMCO pays these employees total compensation comprised of three interrelated components—base pay, short-term incentive compensation, and, where applicable based on position within the Company, long-term incentive compensation.

Q. Are there some employees that do not receive incentive compensation?

A. Yes. Based on the same industry-specific market survey data I mentioned earlier in my testimony, there are positions within the Company that are not generally incentive-eligible. These may include positions in which employees are paid an hourly wage or positions held by union-represented workers. Base pay compensation for non-union, hourly employees is set at the middle of the market, but the pay structure for these employees does not include incentive pay. For the same reason that these full base pay amounts for non-union, hourly employees are a reasonable and legitimate cost of providing service to customers, and are fully recoverable in base rates, so too should a middle of the market compensation formula that includes an incentive based on achievement of goals be recoverable in rates.

II. SEMCO INCENTIVE COMPENSATION PLAN DESIGN

Q. What are the key provisions of the STIP?

A. The STIP covers 133 management and professional employees at SEMCO and SEMCO Gas. Under the STIP, participants are eligible to receive a percentage of their base salary annually, in a lump-sum cash payment, paid only after Company and individual performance compared to STIP targets has been met or exceeded. STIP performance measures are determined annually. Performance against these targets is assessed throughout the year, with the final comparison of performance against targets prepared shortly after the end of the year.

Q. What are the key provisions of the LTIP?

A. The LTIP has 19 SEMCO and SEMCO Gas participants comprised of employees in key decision-making positions (director and above). LTIP participants are a smaller group than STIP participants because the compensation survey data used to calculate “middle of the market” compensation makes it clear that only employees in certain types of positions should receive this type of incentive compensation.

Under the LTIP, participants are eligible to receive a percentage of their annual base salary, in the form of a cash award grant tied to three-year performance objectives. These three-year cumulative objectives are designed to balance efforts in accomplishing annual (STIP) objectives with more long-term, sustainability-type objectives. LTIP payouts depend on the attainment of long-term company and individual objectives. Performance is assessed shortly after the end of the three-year cumulative performance period. Performance measures are selected annually, in advance of each award grant.

III. **CUSTOMER BENEFITS FROM SEMCO'S INCENTIVE PLANS**

Q. Are benefits to customers relevant to the recovery of incentive plan-related costs in rates?

A. Yes. As a Human Resource professional I believe the primary threshold should be that the compensation components, including incentive compensation, are part of a reasonable compensation package that is supported by benchmarking data, such as the survey analysis process discussed earlier in my testimony. But also, because the Commission feels strongly that customers should benefit through incentive plan objectives that serve their best interests, I agree that incentive plans should demonstrate customer benefits. I feel that SEMCO's incentive plans clearly meet that objective.

Q. Describe the primary customer benefits arising from the STIP and LTIP.

A. First, many of the key performance metrics in the LTIP and the STIP focus directly on our customers. The 2018 STIP key metrics Exhibit A-43 (ALF-1) include: average answer time and customer satisfaction score related to the service the Company's call center provides to customers; leak response time, minimizing outages and reducing open non-compliances related to service provided to customers by the Company's operations area; and injury, vehicle accident and reduction in active year-end leak goals centered around safety for our customers, communities and employees. The 2018 – 2020 LTIP also includes customer-benefiting metrics such as; redundancy through construction of the Marquette Connector Pipeline (MCP); enhancement of physical and cybersecurity controls; high-level customer satisfaction scores and managing staffing to provide safe and reliable service.

Second, customers benefit from the Company's ability to attract, motivate and reward its personnel. This objective is achieved by, among other things, compensating employees at market-competitive levels. Our employees ensure that customers receive safe, reliable, and efficient natural gas service. The STIP and LTIP are integral to ensuring that employees focus on the right things to achieve the best outcome for the customers.

Third, SEMCO's incentive plans serve as an invaluable tool in reducing employee turnover. The natural gas industry is already experiencing a significant level of employee turnover as the baby boomers head into retirement. It is imperative that SEMCO is able to hire and retain replacement employees in a manner that ensures adequate training time. Having properly trained employees is a significant benefit to our customers. Incentive plans provide additional reason for employees to remain with the Company. Turnover is costly in recruiting and retraining expense and in the loss of experience. Customers benefit from keeping turnover low in avoidance of these expenses and in maintaining a skilled workforce.

Q. Can the benefits customers derive from SEMCO Gas's incentive plans be quantified?

A. Yes. While every metric is not readily quantifiable, the benefits associated with one measure, well-controlled Operations and Maintenance ("O & M") expenses, highlight the substantial benefit that has in the past, and continues to, accrue to customers.

Q. How has the focus on controlling O & M expenses benefited customers?

A. As discussed in Mr. Moses testimony, SEMCO Gas's total O & M expenses have grown at a rate of .23% per year between 2009 and 2018, compared to the growth in the United States Consumer Price Index ("CPI") during the same time period of 1.76%. Had SEMCO Gas's O & M expense grown at the CPI rate since the last rate case, Total O & M expense in 2018 would have been $7,459,921 higher. Lower O & M expense is a direct benefit to customers.

Q. Do you believe that the incentive plan impacts whether the benefits mentioned above are realized?

A. Yes. The intent and result of the incentive plans is to increase employee focus on realization of the objectives designed into the plans—whether the objective is expense reduction, or increased customer satisfaction. While all metrics are not readily quantifiable, just considering the O & M results noted above illustrates that customers realize significant benefit from the Company's incentive plans. The benefits significantly exceed the incentive compensation expense included in this filing.

Q. Does this conclude your prefiled 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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY OF MATTHEW C. KOSHT

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Matthew C. Kosht
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. My name is Matt Kosht, 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, Inc. ("SEMCO"). SEMCO Energy Gas Company ("SEMCO Gas" or the "Company") is a division of SEMCO.

Q. Please describe your business experience.

A. In my current position, I oversee the Information Technology area for SEMCO. I have held positions of increasing responsibility at SEMCO since 1988, including positions in Information Technology ("IT"), and Gas Control/SCADA systems Administration. I held Supervisor and Manager level positions in IT for SEMCO Gas before moving to my current position.

Q. What are your job responsibilities?

A, As the Director of Information Technology my responsibilities include the management of the IT Staff across all of SEMCO business units in Michigan and Alaska. I am responsible for all of the Company's IT systems, hardware and software, including cybersecurity.

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

A. My testimony describes the cybersecurity enhancement projects that SEMCO has completed in 2018 and has planned for future years, explains why SEMCO needs to complete the planned enhancements for its and its divisions' benefit, including SEMCO Gas, and details the costs associated with the enhancements which are required to maintain and improve the ability to deter cyber threats.

Q. Are you sponsoring any exhibits?

A. No.

Computing Environment

Q. Can you describe the current computing environment?

A. Yes. The current computing environment is similar to other natural gas utilities' environments. SEMCO maintains networks which connects all of its physical locations (inclusive of all of its divisions) to its data center. The data center hosts numerous applications that are required to effectively run the business including a customer information system, a financial and accounting system, an HR and payroll system, a gas monitoring and control system, a voice system to receive calls, and numerous other systems. These systems contain critical information to be used in running the company (inclusive of its divisions) and information about customers and employees.

Cybersecurity Enhancements

Q. What is cybersecurity?

A. Cybersecurity is the protection of internet-connected systems, including hardware, software and data, from cyberattacks. Actions to increase cybersecurity include creating and implementing new policies and practices, implementing new security tools in the computing environment, and increasing physical security at all locations where connection to the company's network is available. All of these are used by enterprises to protect against unauthorized access to data centers and computerized systems.

Q. Will you please describe the security environment at SEMCO prior to 2018?

A. The company's security environment consisted of good, basic, first-level policies, security tools and physical security. Examples include policies on using passwords, documenting changes, user access reviews, and keeping inventories of network devices. Security tools consisted of anti-virus and malware solutions, internet content filtering solutions, firewalls and other standard security tools that most companies utilize. Physical security consisted of locked doors requiring access codes, dedicated data center space, and some video security.

Q. Why is it necessary to complete security enhancements?

A. Cybersecurity threats are more prevalent now than at any time in history. As cybercrime gets more sophisticated, it is important that companies make robust cyber security a strategic item. Systems get compromised through a variety of methods, but the most common are through phishing, malware and password attacks. Through these, hackers can extract confidential information from company systems, shut down critical systems and gain control of company systems for current and future use.

Q. What is the most common types of cyber-attack?

A. Phishing is the most common type of cyber-attack. This is the practice of sending emails that appear to be from a trusted source with the goal of gaining personal information, including login information, or of loading malware onto a computer. The emails may also send users to false websites which contain exploits that get loaded on the user's computer. Most breaches occur from a successful phish.

Q. What could be the result of a successful phish?

A. With a successful phish, many results could occur. The hacker could install a program to monitor activity on SEMCO's networks to gain an understanding of the systems and users. This may occur to gather information for a larger scale attack in the future. Ransomware may be installed on SEMCO's network. This is an exploit from a malware that encrypts information and makes a "key" to unencrypt the information available if the affected company pays a "ransom" to the hacker. Critical information may be lost if the information cannot be retrieved. Hackers can steal and export personal and confidential information on SEMCO's customers, financials or pipeline. In a worse case, hackers could gain control of SEMCO's networks and systems and perform actions detrimental to the company and its stakeholders.

Q. What other drivers are there to support implementing security enhancements?

A. SEMCO participates with numerous organizations to gain knowledge and industry recommendations for security. These organizations include the American Gas Association and the Information Security Forum ("ISF"). SEMCO has participated in calls and sessions on the changing threat landscape for utilities and recommendations on how to reduce security risks. SEMCO has also used security assessment tools from both organizations to evaluate its current security status. The communication and engagement with these organizations show that SEMCO is at a good, base level of security practices and tools. But, to enhance the security posture at SEMCO and to reduce the security risks and rise to a higher level of protection, SEMCO is required to have dedicated staff focused on security, to create additional and more robust policies and procedures, and to implement additional and newer security tools for network access, security monitoring and protection. These were also the recommendations from the last security assessment SEMCO had completed by PWC during the last quarter of 2017. PWC used the Security Healthcheck assessment tool from the ISF. SEMCO scored in the middle of 5 categories of security capability and maturity. SEMCO's strategy is to move to a higher level of capability and maturity, which will greater protect the company (inclusive of tis divisions) and its stakeholder from security threats. To achieve this, SEMCO must implement the security enhancements discussed in this testimony.

Q. How would enhancements to SEMCO's security state create a more robust security environment?

A. Security enhancements would reduce the risk of threats from hackers being successful and would greatly increase SEMCO's monitoring and awareness of the activities on its networks. This would assist in thwarting attempted attacks and in limited the

Q. What security enhancements has the company completed during 2018?

A. The Company's cybersecurity enhancements consisted of staffing a department within the IT Department focused on the company's security requirements. This department, called the Security Operations Center ("SOC") is responsible for the cybersecurity initiatives in the company including initiatives for cybersecurity awareness and training, for completing regularly planned phishing exercises of employees, for monitoring employee results of cybersecurity testing and taking follow-up action as required, for creating and gaining approvals for new cybersecurity policies and procedures, and for providing alignment, guidance and resources for numerous cybersecurity infrastructure and application initiatives.

Q. Can you list the cybersecurity infrastructure and application enhancement initiatives for 2018?

A. The Company had 3 major infrastructure security enhancements during 2018. The implementation of 2-factor authentication, the implementation of 24/7 365 monitoring of SEMCO's networks, and the implementation of identity services for access of SEMCO's networks.

Q. Describe how 2-factor authentication helps SEMCO reach a more robust cybersecurity state.

A. The 2-factor authentication provides additional security on who can login to SEMCO's network. Traditionally, a user needed a user name and a password to access SEMCO's systems. In 2018 SEMCO implemented a security solution that requires an additional code to login to SEMCO's systems. This means that if a hacker was able to obtain a valid user name and password for login, they would not be able to exploit that information. They would also need the additional code, or second factor, which is presented to users via their smartphone or other physical device.

Q. Describe how 24/7 365 monitoring helps SEMCO reach a more robust cybersecurity state.

A. SEMCO began implementation of a network monitoring solution during 2018. The solution, called a System Information and Event Management system ("SIEM"), monitors all activity on SEMCO's networks by collecting and aggregating log data generated throughout the organization's technology infrastructure, from host systems and applications to network and security devices such as firewalls and antivirus filters. The SIEM then checks all activity for known exploits and potential harmful activity. To be effective, the information gathered requires 24/7 365 monitoring of the dashboard, so that potential and known threats can be investigated. SEMCO has contracted with a firm in Georgia, Cybriant, who specializes in SIEM monitoring to provide this service. This provides SEMCO with robust monitoring of its networks and activities so that it is more likely that threats can be stopped and that successful exploits can be mitigated much quicker.

Q. Describe how identity services helps SEMCO reach a more robust cybersecurity state.

A. SEMCO started the installation of a network access control system ("NAC") during 2018. This NAC product is a network administration product that enables the creation and enforcement of security and access policies for endpoint devices connected to the company's routers and switches. The purpose is to simplify identity management across diverse devices and applications. The product can prevent devices which are not identified as SEMCO devices from logging in to the network. Devices which have not been patched properly or do not have up-to-date anti-virus and malware applications installed can also be stopped from logging in to the network and accessing SEMCO's systems. The NAC also enables SEMCO to logically segregate its networks and applications so that if a breach were to occur, the damage would be limited to the segment(s) of the network that the device is permitted to access.

Q. Is there additional work required around the 3 security projects discussed above?

A. Yes. SEMCO made tremendous progress on the infrastructure enhancements during 2018, but additional work is required during the next couple of years on the SIEM and ISE products to get the maximum benefit and security for the Company. The 2-factor will be approximately 90% completed at yearend.

Q. Are there additional enhancement tools that will be required to achieve SEMCO's security requirements and goals?

A. Yes. SEMCO is planning to replace its current endpoint protection tools with a modern heuristic solution. Instead of identifying security threats from a list of known items, the newer tools also identify threats from patterns of activity on the network. This provides an additional layer of security. SEMCO is also going to replace its email filtering solution with a more capable solution that provides better protection from advanced threats. Again, the newer solution offers additional protections for the company. SEMCO is also installing a mobile device protection management solution that will enable encryption of all mobile devices and provide management tools that can assist with the overall security plan at SEMCO. Other items to be implemented include replacing core switches to support the NAC implementation, implementing a Credential Management System, implementing a File Classification System, adding additional sensors on the network to support the SIEM, adding additional licenses for server vulnerability scanning, implementing a Firewall Management Tool, implementing Hardware Canary Tokens, and all of the associated labor to complete these security projects.

Q. What were the expenses for the 2018 cyber security enhancements?

A. In 2018 SEMCO had $62,225 of expenses related to cyber security enhancements. This was comprised of $39,225 related to Labor and $23,000 related to services. The 2018 cybersecurity enhancement expenses only reflect about 6 months of spending for labor, as the SOC was not in place until the second half of the year.

Q. What is the projected expenses for 2020?

A. There are 3 primary costs associated with the implementation and maintenance of the security enhancements. They are the hardware and software security product solutions, the annual cost for maintenance and services around the solutions, and the SEMCO internal labor required to implement and maintain the solutions and coordinate the security efforts at SEMCO. The 2020 projected expenses for cybersecurity enhancements is $210,536. The projected 2020 expense is comprised of $83,228 of Labor and $127,308 of services. The 2020 labor expenses associated with cybersecurity enhancements are higher due to the fact that the SOC was not in full operation in 2018 until July. The labor costs associated with the SOC will be for a full year going forward.

q. How are these cost allocated from SEMCO to SEMCO Gas?

A. Witness Moses in his testimony describes the methodology for allocating costs.

Q. Are the costs for cybersecurity going to be required for years past 2020?

A. Yes. The solutions that are being implemented at SEMCO over the next several years will require regular upgrades to remain current, work with SEMCO networks and operating systems, and so that they remain supported by the vendors. Major upgrades of IT solutions being discussed in this testimony would typically occur every 3-4 years. The vendor costs and SEMCO labor costs to perform the upgrades would be similar to the costs of the original implementations. Also, the current costs incurred for monitoring services and for the internal security team will remain and increase on an annual basis.

Q. Does this complete your 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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF LAURIE K. OWENS

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2018

Direct Testimony of Laurie K. Owens
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address, and business title.

A. My name is Laurie K. Owens. My business address is 1411 Third Street, Suite A, Port Huron Michigan 48060. My current title is the Director of Business Support Services for SEMCO Energy Gas Company ("SEMCO Gas" or the "Company").

Q. Please describe your educational background and business experience.

A. In 1999, I graduated from Walsh College of Accountancy and Business Administration, Troy, Michigan, with a Bachelor's degree in Accountancy. I have held positions of increasing responsibility at SEMCO Gas since 1988. As the Director of Business Support Services, I am responsible for the oversight of Customer Accounting, Call Center, Service Dispatch, Business Applications and Business Services, including low-income programs.

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

A. The purpose of my testimony is to support the approval of the following operational changes:

1) The implementation of a new low-income program;

2) The elimination of the convenience fee for credit card, debit card and electronic check payments;

3) The elimination of the fee charged to leave a shut off notice at a customer's premise; and

4) The miscellaneous revenue adjustment associated with the Appliance Repair Program

Q. Are you sponsoring any exhibits in this case?

A. I am sponsoring the following exhibits:

Exhibit A-17 (LKO-1): Credit Card Processing Expense

Exhibit A-18 (LKO-2): ENSTAR Transactions as Percent of Customer Base

Exhibit A-19 (LKO-3): Appliance Repair Program Costs

Q. Were these exhibits prepared by you or under your directions?

A. Yes.

LOW-INCOME ASSISTANCE PROGRAM

Q. Why is SEMCO Gas reviewing the merits of a residential income assistance program in this case?

A. SEMCO Gas and its employees have a culture of giving generously to the Company's customers and the communities it serves by participating in volunteer positions and donating to various funds. For example, this year SEMCO Gas is celebrating its 11th annual energy drive golf tournament with all proceeds to benefit The Heat and Warmth Fund (THAW). Further, in the Commission Order Approving Settlement Agreement in the Company's last general rate case, U-16169, the Company was directed to "address the merits of a residential income assistance program".

Q. Please describe the program the Company is proposing to implement to assist its low-income customers?

A. The Company is proposing to implement a Low-income Assistance Credit ("LIAC") program to support low-income customers needing assistance with their natural gas heating bills. The goal of the program is to decrease customer disconnects due to nonpayment by providing some of SEMCO Gas's most vulnerable customers with an affordable payment option for their heating bills. Enrollment in the program will focus on those customers with the highest need.

Q. What are the key components of the LIAC program?

A. The LIAC program will provide a credit of $30.00 towards the customer's distribution charge each billing month for eligible low-income residential customers. To qualify for this program, the customer's household income cannot exceed 150% of the Federal Poverty Level, which must be confirmed by an authorized State, Federal, or community agency. The customer may also qualify if he has received a Home Heating Credit in the previous 12 months, or received any of the following state assistance programs: (i) State Emergency Relief ("SER"), (ii) food stamps, or (iii) Medicaid. Enrollment will be based on Company selection and limited to 3,200 participants. The program will focus on those customers with the highest need as identified by the Company The forecast was determined using existing customer billing information and low income program data. Company Witness Jennifer Dennis uses the forecasted enrollments to calculate the cost of the LIAC program and related rate recovery.

Q. Will SEMCO Gas's current low-income customers be eligible for this new program?

A. Yes, the program will be able to provide support to Company customers that meet the qualification requirements, with emphasis given to the most vulnerable customers, or those with the highest energy burden. The program will provide assistance to eligible low-income customers including those currently enrolled in the Company's Monthly Assistance Program ("MAP"), and those that have graduated from MAP but still require support.

Q. How will customers be selected for enrollment in the LIAC program?

A. Enrollment in the LIAC program will focus on those customers with the lowest income and highest energy burden. Priority will be given to customers at 110% FPL or below where known, those that have graduated from MAP but still require additional assistance, and those customers who were never enrolled. Customers currently enrolled in MAP may receive LIAC in situations where additional customer support is required to manage their energy burden.

Q. When will enrollment in the low-income program begin?

A. Assuming approval of the program, enrollment in the LIAC program will begin with the effective date of the Commission's final order in this case. The Company will select customers for enrollment based on those with the highest need. The LIAC program will be limited to 3,200 participants annually but may be adjusted based on available funding. Any remaining funds at the end of the program year will be carried over into the subsequent program year.

Q. How was the 3,200 enrollment target determined?

A. The enrollment target was determined by analyzing usage data for customers who were previously identified as low income. This total was adjusted for various factors including the Company's MAP participation and consumption thresholds. The enrollment target also considered the overall financial impact from a rates perspective. With the LIAC program being new to SEMCO Gas, it was important to keep the enrollment target manageable for purposes of measuring results and identifying future opportunities.

Q. Will customers enrolled in the LIAC program be referred for Energy Waste Reduction (EWR) services?

A. Yes. Each month the Company currently provides CLEAResult, SEMCO Gas's implementation contractor for EWR, a listing of known low-income customers for purposes of outreach. CLEAResult then uses this list to provide eligible low-income customers with information on home energy assessments, weatherization and health and safety items. Customers may also be eligible to receive additional premium services including furnace or water heater replacement and home insulation. Those customers enrolled in LIAC will be identified and given priority in outreach efforts. If the customer chooses to participate, the EWR program, simultaneous with LIAC, will reduce their overall energy burden and increase the opportunity for self-sufficiency.

Q. How will the low income credits associated with the LIAC be allocated?

A. The credits for the LIAC will be allocated to all rate classes as reflected on Page 2 of Exhibit A-16 (JLD-3) Schedule F-2.2, as sponsored by Company Witness Jennifer Dennis.

Q. Will you be submitting a new tariff to support the addition of the new low-income program?

A. Yes. Please see the direct testimony and related exhibit of Company Witness Jennifer Dennis, who will be sponsoring all proposed tariff changes.

Q. Will the new program, if approved, eliminate any existing low income programs SEMCO Gas is currently offering?

A. No, it will not.

<u>CREDIT CARD PAYMENTS</u>

Q. What is SEMCO Gas proposing for credit card payments and the related miscellaneous revenue?

A. SEMCO Gas is proposing to stop charging a customer convenience fee when making a debit card, credit card or electronic check payment through SEMCO Gas's third-party payment provider, Invoice Cloud. This will result in a reduction of miscellaneous revenue received by the Company.

Q. Please explain SEMCO Gas's payment service offered through Invoice Cloud.

A. SEMCO Gas uses a third-party payment provider, Invoice Cloud, for customer payments made using a debit card, credit card or an electronic check. The customer may elect to make these payments through the Company's website, its automated Interactive Voice Response ("IVR") system, or a call center representative. For customers that elect to make a one-time payment using a debit card, credit card or electronic check, a convenience fee of $3.50 is assessed.

Q. Please explain how the convenience fee is shared between SEMCO Gas and Invoice Cloud.

A. The revenue from the $3.50 convenience fee is shared between Invoice Cloud and SEMCO Gas. For each payment received, Invoice Cloud retains $2.00 of the convenience fee whereas, SEMCO Gas receives the remaining $1.50. Invoice Cloud is responsible for the expenses associated with the processing of these payments.

Q. What change is SEMCO Gas proposing for the processing of these types of payments?

A. SEMCO Gas will continue to utilize Invoice Cloud for payment processing but is proposing to eliminate the $3.50 convenience fee that customers currently pay for this payment option. By eliminating the fee, the Company will no longer collect the revenue from the convenience fee and instead, will incur the expense associated with the processing of these payments through Invoice Cloud, which is currently $2.00 per transaction.

Q. What is the miscellaneous revenue adjustment associated with ending the convenience fee?

A. As illustrated in Company Witness Mr. Mark Moses Exhibit A-13 (MAM-3), Schedule C-3.1 the adjustment to miscellaneous revenue is $618,284 and is based on the 2014-2018 five year average.

Q. What are the benefits of eliminating the convenience fee for customers?

A. Elimination of the fee will improve customer satisfaction and provide another affordable payment option for customers. Also, DTE Energy and Consumers Energy have already eliminated the fee charged for credit card payments, so this would align the Company with the credit card practices of the other two large utilities in Michigan.

Q. Will SEMCO Gas expect to see an increase in the utilization of the Invoice Cloud payment service?

A. Yes, using transactions from December 2018 of 44,533, the Company expects to see its credit and debit card usage increase from 14.6% of SEMCO Gas's residential and small commercial customers to 37% or 112,808 within one year of implementing the change. The 37% participation rate is based on the growth ENSTAR Natural Gas Company (ENSTAR) experienced with the elimination of the convenience fee model in 2016. Exhibit A-18 (LKO-2) shows how ENSTAR's participation rate increased from 15% of the customer base in February 2016 when the convenience fee was eliminated to 38.1% of the customer base by January 2017. SEMCO Gas anticipates that the majority of the growth impact from implementation of the zero fee model will be realized within the first year. After the first year, it is expected that the transaction growth will be relatively normal starting at the projected participation rate of 37% of SEMCO Gas's residential and small commercial customers.

Q. What customers are eligible to pay with a credit card?

A. SEMCO Gas's residential, and small commercial customers are eligible to make a payment with a credit card. The Company's other customers can continue to make a payment utilizing SEMCO Gas's traditional payment methods including electronic check.

Q. What other change is SEMCO Gas proposing to its credit card program?

A. SEMCO Gas is planning to offer a recurring credit card option, Autopay, to residential and small commercial customers. This will allow the Company to automatically charge the customer's credit card each month on the billing due date. This provides the customer with a convenient payment option that promotes on-time bill payment and improves customer satisfaction.

Q. Please explain the payment processing expense shown in Exhibit A-17 (LKO-1).

A. The payment processing expense of $2,707,397, was calculated using payment utilization data from Enstar and applying the same growth trend for SEMCO Gas.

<u>COLLECTION NOTICE FEES</u>

Q. What change is the Company proposing to its process for notice of shut off?

A. Currently, to comply with the Consumer Standards and Billing Practices R460.139, Company personnel hand deliver a notice of shut off to a customer's premise when the gas service is scheduled to be disconnected for a past due balance. When it becomes necessary to leave a notice of shut off at a customer's premise, a fee of $11.50 is assessed.

Q. What policy change is SEMCO Gas proposing to make to its collection process?

A. SEMCO Gas is proposing to eliminate the fee that is assessed when it is necessary to leave a notice of shut off at a customer's premise. The Company believes the fee places an unnecessary burden on some of SEMCO Gas's most vulnerable customers who are often the least able to afford the additional charge.

Q. How will this policy change impact the process for notifying a customer of a pending shut off?

A. It will not. Customers who are at risk of having their service shut off will continue to receive notice as required by the Consumer Standards and Billing Practices R460.139.

Q. What is the miscellaneous revenue associated with ending the collection notice fee?

A. As illustrated in Company Witness Mr. Mark Moses Exhibit A-13 (MAM-3), Schedule C-3.1 the adjustment to miscellaneous revenue is $608,200 and was determined by averaging the actual revenue collected from the collection fees assessed for the time period 2014 through 2018.

<u>APPLIANCE REPAIR PROGRAM</u>

Q. Please explain SEMCO Gas's partnership with HomeServe USA.

A. SEMCO Gas has partnered with HomeServe USA ("HomeServe") for approximately 10 years to provide appliance repair coverage to SEMCO Gas's customers. HomeServe is responsible for marketing the plan, processing enrollments and cancellations, handling calls from customers with questions and arranging for service work. For customers that elect to purchase a plan, SEMCO Gas will include the cost of the plan on the customer's monthly gas bill.

Q. Please explain SEMCO Gas's Sales through Service program.

A. Through a program called Sales through Service, SEMCO Gas's Customer Service Representatives ("CSR") may offer the appliance repair plan to customers. The representative is paid an incentive for each plan sale. For the Sales through Service program, SEMCO Gas receives from HomeServe $15 per plan sold to cover the CSR incentive and any expense related to promotional activities to encourage sales within the call center.

Q. How does SEMCO Gas currently record the revenue associated with the appliance repair plan sales?

A. Each month, SEMCO Gas retains 15% of the amount collected from customers. The remaining amount is paid to HomeServe. The Company has historically treated this revenue as a credit to expense.

Q. **Please explain how expenses associated to selling and administering the appliance repair plan are handled?**

A. The expenses associated with selling and administering the HomeServe program are tracked in the general ledger separately. Each month, an allocation is recorded for time spent selling the plan in the call center, reviewing promotional materials and performing activities related to billing, including bill print and mail service. Exhibit A-19 (LKO-3) shows that 1.5625% of the space on the customer bill is allocated for HomeServe. This percentage along with the average cost per bill for the month, and the approximate number of HomeServe customers is used to calculate the monthly expense. The labor associated with reviewing promotional materials and administering the program is charged directly as incurred. The time CSRs spend selling the plan is assumed to be 0.25 hours of each CSR's work week. The expense is calculated by multiplying 0.25 hours by their current hourly rate. In 2018, the expense for administering the program totaled $16,699. This included $1,758 for supervisor labor, $7,285 for CSR labor, $2,481 for bill processing and $5,175 for CSR incentives and call center promotional activities. In this same year, revenue totaled $626,202 resulting in a net revenue of $609,503. The adjustments to move the related net revenue will be supported in the direct testimony and exhibits of Company Witness Mr. Mark Moses.

Q. **Please explain why SEMCO Gas is proposing to make a change with how net revenue for the HomeServe Appliance Repair program is recorded.**

A. SEMCO Gas is proposing to change how it records the net revenue resulting from the sale and administration of the HomeServe Appliance Repair program in accordance with the Code of Conduct for Value Added Programs and Services approved in Case No. U-18361.

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

A. Yes

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF STEVEN Q. MCLEAN

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Steven Q. McLean
On Behalf of
SEMCO Energy Gas Company

Q. Please state your name and business address.

A. My name is Steven Q. McLean. My business address is 1411 Third Street, Port Huron, Michigan 48060.

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

A I am employed by SEMCO Energy Gas Company ("SEMCO Gas" or the "Company"), a division of SEMCO Energy, Inc. ("SEMCO"), as its Director of Regulatory Affairs.

Q What are your responsibilities as Director of Regulatory Affairs?

A I am responsible for all SEMCO Gas regulatory matters involving the Michigan Public Service Commission ("MPSC" or the "Commission') and the Federal Energy Regulatory Commission. In addition, I am responsible for the Company's Energy Waste Reduction Program.

Q. Would you briefly describe your educational background?

A. I earned a Bachelor's of Science Degree in Political Science and Economics from Central Michigan University in May 2003. I earned a Master's of Arts Degree in Economics from Central Michigan University in December 2007.

Q. Have you attended any seminars or other training courses?

A. Yes, in May 2006, I attended the Association of Edison Illuminating Companies' Fundamentals of Customer Load Analysis Seminar. In August 2006, I completed the National Regulatory Utilities Commissioners' annual regulatory studies program held at Michigan State University. In October 2010, I attended the Association of Edison Illuminating Companies' Advanced Course in Customer Load Research.

Q. Please summarize your employment and professional experience.

A. In January 2006, I joined the MPSC where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities, utilizing laws, regulations, and Commission policies. In August of 2014, I was hired by SEMCO Gas as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to my current position as Director of Regulatory Affairs.

Q. Have you previously testified in any regulatory proceedings before the Commission?

A. Yes. I have testified before the MPSC in numerous general rate cases and other miscellaneous proceedings on behalf of the MPSC Staff and SEMCO Gas.

Q. Please identify the exhibits which you are sponsoring in this case.

A. I am sponsoring:

Exhibit A-13 (SQM-1), Schedule C-4 – Projected Cost of Gas Sold

Exhibit A-13 (SQM-2), Schedule C-4.1 – Company Use, LAUF and GIK

Exhibit A-46 (SQM-3) – Special Contract Customer Maps

Exhibit A-47 (SQM-4) – Transportation Discount Summary and Allocation

Exhibit A-48 (SQM-5) – Main Replacement Revenue Requirement

Exhibit A-49 (SQM-6) – Main Replacement Surcharge Calculation

Exhibit A-50 (SQM-7) – Infrastructure Replacement Revenue Requirement

Exhibit A-51 (SQM-8) – Infrastructure Replacement Surcharge Calculation

Exhibit A-52 (SQM-9) – Kansas Ad Valorum Tax Expense & Amortization

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

A. Yes.

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

A. The purpose of my testimony is to address the recovery of the special contract discounts; the calculation of the Main Replacement Program ("MRP") surcharges for the years 2021-2025; the calculation of the proposed Infrastructure Reliability Improvement Program ("IRIP") surcharges for the years 2021-2025; recovery of the Kansas ad Valorem tax ("Tax"); recovery of the regulatory expense related to the rate case; calculation of Company Use, Lost and Unaccounted for Gas ("LAUF"), and Gas in Kind ("GIK") rate.

Special Contract Discounts

Q. Does the Company currently have any special transportation contracts with customers that are discounted from tariffed rates?

A. Yes, the Company currently has five customers served under discounted special contracts approved by the Commission. In the Battle Creek service area, WestRock, Graphic Packaging, and Post Foods LLC ("Post") are served through special transportation contracts. In the Upper Peninsula ("U.P.") service area, the Company serves Michigan Technological University ("MTU") and U.P. Paper LLC ("UP Paper") through special transportation contracts. Due to the history and nature of the bypass threat related to Graphic Packaging, Post, and WestRock, I will address them in a combined manner as the ("Batter Creek Customers")

Q. Why did SEMCO Gas negotiate discounted special transportation contracts with these customers?

A. SEMCO Gas negotiated discounted special contracts with the Battle Creek Customers and UP Paper to prevent them from bypassing SEMCO Gas's system and retain them as End Use Transportation customers. These are some of SEMCO Gas's largest customers, each with annual consumption of between approximately 725,000 Dekatherms to over 1,200,000 Dekatherms per year. In addition, the facilities of these customers are located within a few miles of interstate pipelines. The combination of their substantial annual consumption and proximity to an interstate pipelines means that these customers have a high potential to bypass SEMCO Gas's distribution system. If these customers were to bypass the Company's distribution system, they would no longer contribute to SEMCO Gas's recovery of fixed system costs causing those fixed costs to be spread out to and paid by SEMCO Gas's other customers. The maps sponsored as Exhibit A-46 (SQM-3), show how close these customers are to an interstate pipeline from which they could receive natural gas service.

Q. Why did the Company negotiate a special transportation contract with MTU?

A. The Company agreed to negotiate a special transportation contract with MTU as a part of the Settlement Agreement in Case No. U-16169. Due to the low usage of MTU, relative to the MCL 460.6a(7) legislative requirement of 500,000 Dth, SEMCO Gas is not requesting the recovery of MTU's discount from other customers. To achieve this outcome SEMCO Gas has included MTU's billing determinants in the TR-2 rate calculation on Exhibit A-16, Schedule F3 sponsored by Witness Dennis. MTU's special contract rates are also displayed on Exhibit A-16, Schedule F3 but are for informational purposes only and are not included in the present or proposed revenue calculation.

Q. Please describe the bypass threat for the customers located in the Battle Creek service area.

A. In 1998, two of the four customers in Battle Creek, WestRock (formally Rock-Tenn) and Graphic Packaging (formally Altivity and Michigan Paperboard), threatened to bypass SEMCO Gas's distribution system. These customers retained Fowler Energy, an energy consulting company, to review energy source options and to determine a strategy for reducing the energy costs. Fowler Energy determined a bypass option was feasible even if only one customer bypassed SEMCO Gas's distribution system. That bypass option was more attractive if two or more customer participated in the project. WestRock and Graphic Packaging are located near one another, and both customers could bypass SEMCO Gas's system with a common bypass line.

Q. Did the Battle Creek Customers reveal other factors affecting their thinking about bypass?

A. Yes, SEMCO Gas was told that each customer must compete globally in selling its products and compete internally with other production facilities to continue producing their products in Battle Creek. They explained that, if their costs are higher than their competing production facilities in other parts of the United States or the world, they would seek to reduce their costs in any way possible, including bypassing SEMCO Gas or else production would be moved to those other facilities.

Q. What happened with the other Battle Creek Customers?

A. During this process, Post Foods LLC (formally Kraft Foods) also said that it would pursue bypass if it did not receive a discounted rate.

Q. Why did SEMCO Gas believe the bypass threat was valid?

1A. Fowler Energy had performed a detailed bypass analysis. That 1998 analysis estimated that an 18,000 foot bypass line would cost $1,076,323. In addition, WestRock (Rock-Tenn) had previously bypassed a distribution system in Pennsylvania. From SEMCO Gas's perspective, the load of each customer was sufficient to justify the expense of bypass, both individually and especially if the costs of bypassing SEMCO Gas were shared among the group. The bypass costs in the Fowler Energy study appeared to be reasonable to SEMCO Gas personnel, who have their own expertise in evaluating pipeline extensions and related facilities.

Q. Back in 1998, why did SEMCO Gas choose to negotiate special transportation contracts rather than let these customers bypass SEMCO Gas's distribution system?

A. Allowing these customers to bypass the SEMCO Gas distribution system would end their contribution to the Company's fixed costs and shift a significant fixed cost burden to SEMCO Gas's other customers. The Company determined that it was better, for both customers and shareholders, to have some contribution to fixed costs from these customers rather than no contribution. Collectively these customers contribute approximately $1,598,688 toward the Company's fixed costs annually under their discounted rates.

Q. Is the bypass threat still viable for these three customers in Battle Creek?

A. Yes. In 2019, SEMCO Gas's Engineering Department estimated the cost of constructing a bypass line to WestRock. The estimate included the construction of a gate station at ANR's pipeline, installation of approximately 15,000 feet of 4 inch steel piping, and the placement of associated measurement, regulation and odorization equipment. The estimate indicated that the total cost for the project would be approximately $4 million. Based a 10-year payback analysis, the cost for the project would be approximately $627,500 per year. This would be less than the annual cost of if all three customers shared this cost, the per customer cost each year would be $425,833. Even with the increase in costs compared to the analysis done in 1998, the Company's judgment is that bypass remains a viable threat and that it is appropriate to continue to provide service to these customers under special transportation contracts.

Q. Has SEMCO Gas negotiated new contracts with the Battle Creek Customers since 1998?

A. Yes. The Company negotiated new contracts in 2011. These contracts were then amended in 2016. These contracts were negotiated individually with each customer in good faith. These contracts were approved by the Commission.

Q. Please describe the bypass threat for UP Paper?

A. UP Paper was formed in 2016 and operated in the former Manistique Papers' mill which closed in 2015. Prior to closing, Manistique Papers worked with SEMCO Gas to replace coal with natural gas as the primary fuel source. As a part of this process SEMCO Gas provided a discounted rate under the Coal Displacement provision of the Company's End Use Transportation tariff. In 2017, SEMCO Gas was approached by UP Paper requesting the same discounted Coal Displacement rate. At the time the customer indicated that it was reviewing all options to lower their fuel costs. Due to UP Paper's proximity to Great Lakes Interstate Pipeline ("Great Lakes") and significant usage, SEMCO Gas determined that UP Paper was a potential bypass threat. Based on analysis by SEMCO Gas's engineering group it would cost UP Paper approximately $3.1 million to directly connect with Great Lakes and bypass SEMCO Gas. Based on a 10 year payback this would cost UP Paper $310,000 annually. This would be less than the annual cost under the Company's proposed rates and in the Company's judgement creates a viable bypass threat.

Q. Why didn't SEMCO Gas serve UP Paper under the Coal Displacement provision?

A. Having removed all coal equipment SEMCO Gas determined that the customer no longer met the criteria of the Coal Displacement provision and could only receive a discount transportation rate through a special contract. SEMCO Gas negotiated with UP Paper in good faith and the party's agreed to a special transportation contract which was filed with the Commission and subsequently approved on May 23, 2019, in Case No. U-20340.

Q. What is the Company requesting this proceeding?

A. The Company is requesting to recover the full amount of the discounts associated with the special transportation contracts for Graphic Packaging, Post LLC, WestRock and UP Paper LLC totaling $830,862 annually in accordance with Section 6a(7) of Public Act 3 of 1939, as amended by 2016 Public Act 341, MCL 460.6a(7). These discounts are illustrated on Exhibit A-47 (SQM-4).

Q. What does MCL 460.6a(7) state?

A. MCL 460.6a(7) states the following:

> The commission shall, if requested by a gas utility, establish load retention transportation rate schedules or approve gas transportation contracts as required for the purpose of serving industrial or commercial customers whose individual annual

> transportation volumes exceed 500,000 decatherms on the gas utility's system. The commission shall approve these rate schedules or approve transportation contracts entered into by the utility in good faith if the industrial or commercial customer has the installed capability to use an alternative fuel or otherwise has a viable alternative to receiving natural gas transportation service from the utility, the customer can obtain the alternative fuel or gas transportation from an alternative source at a price that would cause them not to use the gas utility's system, and the customer, as a result of their use of the system and receipt of transportation service, makes a significant contribution to the utility's fixed costs. The commission shall adopt accounting and rate-making policies to ensure that the discounts associated with the transportation rate schedules and contracts are recovered by the gas utility through charges applicable to other customers if the incremental costs related to the discounts are no greater than the costs that would be passed on to those customers as the result of a loss of the industrial or commercial customer's contribution to a utility's fixed costs.

Q. Why should the Commission approve recovery of the discounts provided under the special transportation contracts?

A. The Commission should approve recovery of the discounts consistent with MCL 460.6a(7) for the following reasons:

1. The special contract customers are commercial or industrial customers having transportation volumes greater than 500,000 dekatherms on SEMCO Gas's system;
2. The contracts between SEMCO Gas and the special contract customers were agreed upon in good faith through iterative negotiations;

3. The special transportation contract customers have the capability to use an alternative gas transportation service via the close proximity of interstate pipelines and can obtain this alternative gas transportation service at a price that would cause each customer to not use SEMCO Gas's system.

4. At current rates, the special transportation contract customers make a significant contribution $1,598,688 to SEMCO Gas's fixed costs in the projected test year. In addition, these customer's will contribute to the Company's prosed MRP and IRP by paying the surcharges and will contribute an additional $72,000 per year for the 2021-2025 period. The net present value, to other customers, of retaining the special contract customers over a five year period is approximately $7.9 million.

Furthermore, the incremental costs resulting from providing the discounted rates $830,862 are significantly less than the contribution these customers make to covering SEMCO Gas's fixed costs. If these customers bypass SEMCO Gas's system, costs currently allocated to them would be shifted to the remaining customers. Specifically, the revenue requirement from the Residential customer class will increase by $2,212,101, and the revenue requirement from General Services will increase by $1,730,189 as illustrated on Exhibit A-47 (SQM-4). If these special contract customers leave the system, it will also impact MRP surcharges as well. Approximately $76,000 per year of revenues collected for the 2021-2025 period to be paid by these special contract customers will be collected from other customers.

<u>Main Replacement Program</u>

Q. Please discuss the Company's MRP.

A. SEMCO Gas initiated the MRP consistent with the MPSC's January 6, 2011 Order approving the Settlement Agreement in Case No. U-16169. One component of the MRP is a monthly per customer meter charge applicable to all of the Company's customer classes. The initial MRP surcharge was based on a five year average (2011-2015) of incremental capital costs associated with the MRP projects. As part of the MRP, the Company began billing the MRP charge in June 2012.

In December of 2012, in Case No. U-17169, the Company requested to expand the MRP to include vintage plastic and double the annual miles replaced for the period of 2013-2015. As a part of the request, the Company recalculated the monthly per customer meter charge based on the increased spending for the period of 2013-2015. On May 29, 2013, the Commission approved the request stating:

> "The Commission finds that the safety benefits, cost savings, and environmental benefits associated with the proposed expansion justify the surcharge. The request is reasonable, prudent, and in the public interest."

The new surcharges were implemented for the June 2013 billing month and were set to expire on May 31, 2017. While the surcharges continue through May of 2017 the approved spending recovery was schedule to end December 31, 2015.

In January of 2015, In Case No. U-17824, The Company filed to extend the MRP for the period of 2016-2020 and to adjust the surcharge calculation to include certain costs that had been excluded under the original methodology. The parties subsequently settled the case and the Commission approved the Settlement Agreement with new surcharges beginning in June of 2015 and ending in May of 2020.

Q. Please discuss the changes to the Company's MRP proposed in this case.

A. As described by Company Witness Singer, SEMCO Gas is proposing to extend the MRP for the period of 2021-2025. As a part of this extension the Company is proposing to end the current surcharges and implement new MRP surcharges effective on January 1, 2021. The new surcharges are designed to recover the average incremental capital investment for the period of 2021 thru 2025. The surcharges are based on the cost recovery methodology, approved in Case No. U-17824, for MRP specific capital investment which include a return on rate base, depreciation expense, property tax expense and offsets for accumulated deferred taxes and leak savings. The surcharges will remain in place until a future contested proceeding.

Q. Why is the Company proposing to end the current surcharges?

A. The Company is proposing to roll all of the MRP capital investment for the period of 2011 through year-end 2020 into rate base to be recovered through the Company's normal distribution base rates. The Company uses year-end 2020 to better align the capital investment with the recovery period. Therefore, the current surcharges will no longer be necessary when distribution rates are set in this proceeding. New surcharges will be necessary to recover the cost of the MRP extension for the period of 2021-2025.

Q. Please describe page 1 of Exhibit A-48 (SQM-5).

A. Exhibit A-48 (SQM-5) calculates the 2021 – 2025 average revenue requirement of $3,996,809 that was used to develop the customer surcharges. The yearly incremental investment associated with the MRP is illustrated on line 1 of the exhibit. Lines 2-6 calculate the average net rate base. The average net rate base is calculated by taking the cumulative capital investment on line 2 and subtracting out the accumulated depreciation and accumulated deferred taxes on lines 3 and 4. The result is the ending net rate base on line 5 which is divided by two and results in the average net rate base on line 6. The average net rate base is then multiplied by the capital charge rate of 10.54% to calculate the return on net rate base shown on line 7. The depreciation expense, property taxes and accumulated savings are then added to the return on net rate base to derive the total annual revenue requirements illustrated on line 11. The five year average five year average revenue requirement is illustrated in column (f).

Q. Is the Company proposing to change the MRP cost recovery methodology?

A. No. The Company is proposing to continue the previously approved methodology from Case No. U-17824. As described by Witness Singer, the MRP program has been very successful. SEMCO Gas has continually met the spending, mileage and reporting requirements of the currently approved program. There is no reason or need to change the methodology.

Q. What is the basis for the 10.54% capital charge rate?

A. The 10.54% capital charge rate is the Company's proposed carrying cost and is based on the weighted rate of debt, preferred stock, equity and associated taxes. This is the same carrying cost proposed for the Company's Customer Attachment Program.

Q. What is the basis for the 2.53% depreciation rate?

A. The 2.53% depreciation rate is the weighted average depreciation rate for the capital investment in the MRP through December of 2018.

Q. Please describe page 2 of Exhibit A-48 (SQM-5).

A. Page 2 of Exhibit A-48 (SQM-5) is used to calculate the accumulated deferred taxes and the property taxes. The deferred taxes are calculated using the 20 year MACRS tax depreciation table and the weighted average 2.53% depreciation rate for the MRP. The property taxes are based on 50 mills which is an approximate average of the Company's system.

Q. Please explain Exhibit A-49 (SQM-6).

A. Exhibit A-49 (SQM-6) calculates the MRP charges based on the 2021 – 2025 average revenue requirement from column (f) of Exhibit A-48 (SQM-5), page 1. All allocation factors on the exhibit have been updated based on the 2020 projected Class Cost of Service Study supported by Witness Raab. Under the originally approved program in Case No. U-16169, the monthly MRP surcharges were capped at a rate of $500.00 per month. The Company is proposing to increase that cap to $1000. The Company is proposing to implement the revised MRP charges on January 1, 2021. The Company proposes that these surcharges remain in effect until a future contested proceeding.

Q. Is the Company proposing to change the current reporting requirements?

A. No. The Company is proposing to continue the current reporting method originally approved in the Commission Order Approving Settlement Agreement in Case No. U-16169, and later orders in Cases No. U-17169 No U-17824. As shown by Witness Singer, the Company has continually met the requirements of the current MRP. The proposed annual spending levels are not significantly more than the levels already achieved by the Company in recent years. The Company has shown that it is willing and able to meet both the miles and spending levels requested in this case. Adding additional reporting requirements are unnecessary and administratively burdensome.

Infrastructure Reliability Improvement Program

Q. Please discuss the Company's proposed IRIP.

A. As described by Witness Singer the Company is proposing to implement the IRIP to complete specific reliability projects to improve SEMCO Gas's distribution system. As supported by Witness Singer, these projects will cost approximately $54.5 million to complete over the 2020-2025 period. In order to maintain the Company's normal capital program as well as mitigate the need for continuous rate case filings SEMCO Gas is proposing to implement levelized surcharges for the 2021-2025 period to recover the related costs.

Q. How were the levelized surcharges for the 2021-2025 period developed?

A. Due to the success of the MRP and the Company's familiarity with cost recovery methodologies the Company is proposing to use the MRP methodology to develop the IRIP surcharges. The surcharges are designed to recover the average incremental capital investment for the period of 2021 through 2025. The surcharges are designed to recover IRIP specific capital investment which include a return on rate base, depreciation expense and property tax expense. The surcharges will remain in place until a future contested proceeding.

Q. Please describe page 1 of Exhibit A-50 (SQM-7).

A. Exhibit A-50 (SQM-7) calculates the 2021 – 2025 average revenue requirement of $4,167,697 that was used to develop the customer surcharges. The year-end incremental plant in service associated with the IRIP is illustrated on line 1 of the exhibit. Lines 2-6 calculate the average net rate base. The average net rate base is calculated by taking the cumulative capital investment on line 2 and subtracting out the accumulated depreciation and accumulated deferred taxes on lines 3 and 4. The result is the ending net rate base on line 5 which is divided by two and results in the average net rate base on line 6. The average net rate base is then multiplied by the capital charge rate of 10.54% to calculate the return on net rate base shown on line 7. The depreciation expense and property taxes are then added to the return on net rate base to derive the total annual revenue requirements illustrated on line 10. The five year average the five year average revenue requirement is illustrated in column (f).

Q. What is the basis for the 10.54% capital charge rate?

A. The 10.54% capital charge rate is the Company's proposed carrying cost and is based on the weighted rate of debt, preferred stock, equity and associated taxes. This is the same carrying cost proposed for the Company's Customer Attachment Program.

Q. What is the basis for the 2.33% depreciation rate?

A. The 2.33% depreciation rate is a weighted average depreciation rate for the projected capital investment in the IRIP.

Q. Please describe page 2 of Exhibit A-50 (SQM-7).

A. Page 2 of Exhibit A-50 (SQM-7) is used to calculate the accumulated deferred taxes and the property taxes. The deferred taxes are calculated using the 20 year MACRS tax depreciation table and the weighted average 2.33% depreciation rate for the IRIP. The property taxes are based on 50 mills which is the average of the Company's system.

Q. Please explain Exhibit A-51 (SQM-8).

A. Exhibit A-51 (SQM-8) calculates the IRIP charges based on the 2021 – 2025 average revenue requirement from column (f) of Exhibit A-50 (SQM-7), page 1. All allocation factors are based on the 2020 projected Class Cost of Service Study. The IRIP charges are calculated in the same manner as the MRP surcharges and include a $1,000 cap for TR-3 customers. The Company is proposing to implement the IRIP surcharges on January 1, 2021. The Company proposes that the surcharges remain in effect until a future contested proceeding.

<u>Kansas Ad Valorem Tax</u>

Q. Please describe the Tax.

A. In 2009, then-Kansas Governor, Kathleen Sebelius signed into law Kansas Senate Bill 98 allowing certain Kansas counties to collect taxes on natural gas stored in underground facilities in the state. After many years of court litigation challenging the law, the matter progressed to the Kansas Supreme Court where a decision was issued in December of 2013 affirming Kansas Senate Bill 98. The Court held that the Kansas statute was constitutional as it applied to local distribution companies that are certified as public utilities under the Kansas constitution. Since the Company has a storage account with NNG who stores a portion of the Company's gas in the State of Kansas, the Company is considered a public utility under the State of Kansas constitution whereby the Company's apportioned gas storage inventory is subject to taxation under Kansas State law.

Q. When was the Tax first paid by the Company?

A. The Company first paid the Tax in 2014. During the period of 2009-2013 the Company was not assessed the Tax due to the legal proceeding surrounding the issue. When the Tax was ultimately upheld as constitutional SEMCO was assessed the Tax and paid it accordingly.

Q. What is the Company's estimated Tax expense for the projected period?

A. The Company's Tax expense for the 2020 estimated to be $282,560. This amount includes both an expense related to the projected 2020 Tax ($53,495) and an amortized portion ($299,065) of a deferred regulatory asset from prior periods. Exhibit A-52 (SQM-9) illustrates the total deferred regulatory asset and the total 2020 projected expense.

Q. Why is there a deferred regulatory asset associated with the Tax?

A. When the Company originally paid the Tax in 2014 it was booked as a cost of gas and included in the 2014-2015 GCR reconciliation Case No. U-17333-R. During that proceeding the Company detailed the volumetric nature and other reasons for why the Tax should be considered a cost of gas and included in the GCR process for recovery. However, Staff witness Dolores Midkiff-Powell argued the Tax was more akin to a personal property tax and should be included in the Company's base rates. In settlement the party's agreed that SEMCO Gas should be authorized to establish a regulatory asset to defer the cost of the Tax for future recovery in a general rate case.

Q. Is the Company requesting to continue to defer the Kansas ad valorem tax?

A. No. The Company is requesting to include the cost of the Tax in base rates and to discontinue deferring future costs associated with the Tax.

Regulatory Expense

Q. Please describe the regulatory expense adjustment the Company is requesting.

A. The Company is requesting to include $266,667 of incremental expense to the 2020 projected test year. This expense represents a three year amortization of the Company's total projected rate case filing cost of $800,000. Due to the infrequency of rate case filings the Company has no regulatory expenses related to rate case filings in the historical year. In addition, the 2019 budget used to develop the 2020 projected period did not include any regulatory expenses related to the rate case filing.

Q. How did the Company determine the $800,000 cost related to the rate case?

A. The Company reviewed the costs associated with the most recent rate case filing in Case No. U-16169 and compared them with the expected resources and time necessary to develop and administer the present case. In Case No. U-16169 the Company spent $590,484. The U-16169 proceeding was settled prior to cross-examination and briefing stages saving costs related to these stages of the proceeding. Based on this prior amount, the potential for a fully contested proceeding, the Company projects that the rate case expense will be $800,000.

Cost of Gas, Company Use, LAUF, and GIK

Q. What is the Company's projected cost of gas expense?

A. The Company's projected cost of gas expense is $154,955,961. As illustrated on Exhibit A-13 (SQM-1), Schedule C-4 the expense was developed by multiplying the Company's projected GCR rate by the total GCR billing determinants in Exhibit A-16 (JLD-4), Schedule F3. This methodology assures that the GCR sales and revenue perfectly align.

Q. What is the Company's projected company use and LAUF expense and related GIK?

A. The Company's projected company use and LAUF expense is $535,434. As illustrated on Exhibit A-13 (SQM-2), Schedule C-4.1 the expense was developed by multiplying the five year average company use and LAUF rate of 0.346% by the projected throughput, then reducing it by the projected GIK. The five year average company use and LAUF rate of 0.346% is also the Company's requested GIK rate.

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

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
SEMCO ENERGY GAS COMPANY	)	
for authority to increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS

OF WALTER E. FITZGERALD

ON BEHALF OF SEMCO ENERGY GAS COMPANY

May 31, 2019

Q. Please state your name, business address, and business title.

A. My name is Walter E. Fitzgerald. My business address is 1411 Third Street, Suite A, Port Huron, MI, 48060. My current title is Director of Gas Management Services for SEMCO Energy, Inc. d/b/a SEMCO Energy Gas Company ("SEMCO Gas" or the "Company").

Q. Please describe your educational background and utility experience.

A. In April 1983, I graduated from Oakland University, Rochester, Michigan, with a Bachelor of Science degree in Mechanical Engineering. In May 1983, I accepted a position with the Company as Staff Engineer after which I attained positions with increasing responsibilities, including Superintendent of Gas Control, Manager of Gas Control, Manager of Production, Transmission, and Storage, Manager of Engineering, and Director of Engineering. Since December of 1999, I have acted as the Director of Gas Supply and Gas Transportation and Director of Gas Management Services. I have received comprehensive training in oil and gas reservoir engineering, natural gas storage engineering, gas well testing, natural gas measurement engineering, utility rates and rate design, regulator station design, along with a wide variety of additional natural gas industry training including accounting, finance, forecasting, natural gas contracting and purchasing strategies, natural gas physical and financial hedging, and purchasing strategies for natural gas liquids.

Q. What are your responsibilities as Director of Gas Management Services?

A. As Director, Gas Management Services, my area of responsibilities include gas supply ("supply"), gas control, and gas measurement. The supply functions currently include planning and contracting for supply, gas storage, along with interstate and intrastate pipeline transportation for the Company's residential and general service customers also known as Gas Cost Recovery ("GCR") customers. Other supply responsibilities include directing the supply related activities associated with third party large volume end-user transportation ("EUT") and the Company's Gas Customer Choice ("GCC") program. Gas control functions include directing activities associated with the monitor and control of the Company's interstate pipeline interconnections, distribution systems, on-system storage reservoirs, compressor stations, along with installation, maintenance, and repair of field SCADA devices. Gas measurement functions include directing activities associated with ensuring accurate measurement of gas received, transported, distributed, and delivered to the Company's customers. Lastly, I provide direction to the Company's Manager of Gas Supply and the Manager of Gas Control.

Q. Have you previously testified in support of the Company's prior cases brought before the Michigan Public Service Commission (the "Commission" or the "MPSC")?

A. Yes. I have either offered pre-filed direct testimony, or testified, on behalf of the SEMCO Gas in all of the Company's GCR cases since 2003 and several tariff revision cases before the Commission.

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

A. The purpose of my testimony is to (i) explain and support material revisions the Rules and Regulations for Transportation Service ("Section E") of the Company's Rate Book for Natural Gas Service ("Tariff"), (ii) explain and support revisions to the Rules and Regulations for Gas Customer Choice Program ("Section F") of the Company's Tariff, (iii) present the price of natural gas in 2020 used by the Company in this case for the purpose of calculating the appropriate revenue requirements for lost-and-unaccounted-for gas, company use gas, uncollectible accounts, and gas in storage inventory, and (iv) to support the working capital adjustment for gas stored underground.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-31 (WEF-01) Rules and Regulations for Transportation Service
Exhibit A-32 (WEF-02) Balancing Recovery Rate Calculation
Exhibit A-33 (WEF-03) Transportation Service Daily Cash-Out Methodology
Exhibit A-34 (WEF-04) Facility Improvement Demand Surcharge Rate Calculation
Exhibit A-35 (WEF-05) Transportation Service Agreement
Exhibit A-36 (WEF-06) Pooling Agreement
Exhibit A-37 (WEF-07) Account Aggregation Agreement
Exhibit A-38 (WEF-08) Off-System Transportation Service Agreement
Exhibit A-39 (WEF-09) Operational Balancing Agreement
Exhibit A-40 (WEF-10) 2020 Cost of Gas Forecast
Exhibit A-41 (WEF-11) Working Capital Adjustment for Gas Stored Underground

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

A. Yes.

Transportation Service Overview, Revisions, and Updates

Transportation Service Overview

Q. Please provide an overview of the transportation service program described in Section E of the Company's Tariff.

A. A SEMCO Gas customer ("Shipper") who elects the Company's transportation service program is choosing to be responsible for the procurement of its own gas supply for delivery to the Company's utility distribution system and for redelivery by SEMCO Gas to the Shipper. All Shippers enter into a Transportation Service Agreement ("Agreement") with the Company, which contain the terms and conditions of their transportation service. When a Customer chooses to be a Shipper, the Shipper arranges for its own gas supplies and upstream delivery to the Company's distribution system. The Company continues to bill the Shipper for monthly fees, distribution charges, balancing recovery charges, cash-out charges, pass-thorough pipeline overrun charges, pass-through pipeline penalty charges, and unauthorized use charges for delivery of the gas to be consumed by the Shipper. SEMCO Gas does not arrange for, or bill the Shipper for the gas commodity. When a Shipper chooses to be a member of a group of Shippers, known as a Pool, located behind the Company's distribution system, the Shipper arranges for its own gas supplies and delivery to the Company's distribution system through a Pooling Agent. In this case, the Company bills the Pooling Agent for the daily balancing recovery charges and cash-out charges associated with the pool of Shippers. All other charges are billed directly to the Shipper. The Pooling Agent typically bills each Shipper of the pool individually for the gas commodity cost procured on behalf of each Shipper.

Q. Does the Company require daily balancing of gas received and gas consumed for individual Shippers and transportation service Pools?

A. Yes.

Q. Please review why the Company requires daily balancing of individual transportation service Shippers and Pools.

A. SEMCO Gas was the first utility in Michigan to require its individual Shippers and Pools to daily balance their gas deliveries and their gas consumption. The Company initially sought approval for daily balancing of its Shippers and Pools in its 1996 general rate case filing, Case No. U-11220. It was necessary for the Company to transition its Shippers from monthly balancing to daily balancing at that time due to unacceptable gas management behaviors exhibited by Marketers of the Company's Shippers. Such unacceptable gas management behaviors resulted in the Company's gas storage assets being prematurely depleted over the very cold winter of 1994 - 1995 resulting in the Company's GCR customers being burdened with unreasonable excess gas costs.

Q. Please explain why it is necessary for the Company to assess balancing and cash-out charges to its Shippers and Pools.

A. The assessment of balancing recovery cost charges and cash-out charges serves multiple purposes. Specifically, these charges serve to (i) minimize the imbalance between the daily and monthly amounts of gas delivered and consumed by Shippers and Pools, (ii) incentivize good gas supply management behaviors among Marketers and Pooling Agents who supply gas to SEMCO Gas's Shippers and Pools, (3) prevent SEMCO Gas's GCR customers from subsidizing the cost of balancing supply and consumption of its transportation service Shippers, (iv) allow for the recovery of SEMCO Gas's allocated upstream pipeline transportation and storage daily balancing costs from the gas transportation service Shippers and for the crediting of those costs to the GCR customer's cost of gas, and (v) limit the level of access that Shippers and Pools have to the Company's limited on-system storage assets at all times.

Q. Do balancing charges and cash-out charges from transportation service Shippers and Pools offset the Company's cost of gas for its GCR customers?

A. Yes. As stated above, all balancing recovery cost charges and cash-out charges are credited 100% to the Company's cost of gas thus offsetting the demand and balancing cost component of SEMCO Gas's GCR factor.

<u>Section E Revisions and Updates</u>

Q. Why is the Company revising Section E of its tariff?

A. After a thorough review of the Company's Transportation Service tariff and the tariffs of all other Michigan gas utilities, SEMCO has identified and made changes to its Transportation Service Tariff to improve the administration of the service, simplify the daily balancing methodology of Shipper services, and to create a more efficient and customer friendly service overall. In addition, the Company plans to replace its gas transportation management and billing system in 2020 whereby simplifying the daily balancing methodology will likely mitigate the acquisition cost of the replacement system.

Q. Is the Company providing revised tariff sheets reflecting its Transportation Service Tariff changes?

A. Yes. Exhibit A-31 (WEF-01) contains a clean version of the Transportation Service tariff reflecting the Transportation Service tariff changes, as well a red-line version.

Q. What changes are being made?

A. The changes being made to Section E of the Company's tariff include the following material revisions:

1. Revised and updated tariff language that supports the Company's planned replacement of its gas transportation management and billing system;
2. Simplification of the Company's transportation service daily balancing methodology;
3. Modification of the transportation service cash-out methodology;
5. Implementation of wireless telecommunication technology;
6. Inclusion of comprehensive gas quality specifications;
7. Recovery of allocated facility improvement demand costs;
8. Cancellation of the alternative communication charge;
9. New legal language;
10. Modifications to the Company's Off-System Transportation Service;
11. New and modified proforma agreements.

Q. Explain why the Company is replacing its gas transportation management and billing system?

A. The Company's gas transportation management and billing system is functionally obsolete and must be replaced. From an Information Technology ("IT") perspective, the system, known as "NaturalNoms", is currently running on an unsupported Windows operating platform. From a billing perspective, the NaturalNoms billing system is inflexible and cannot accommodate certain transportation service billing requirements such as those associated with special contracts and the Company's credits associated with the federal Tax Cuts and Jobs Act of 2017. The NaturalNoms system cannot be modified due to its unsupported operating system. Furthermore, the Company's current daily balancing and cash-out methodology used for its gas transportation service is overly complex and requires simplification for the benefit of SEMCO Gas's Shippers. Such a simplification will have the added benefit of lowering the cost of the replacement transportation management and billing system as it will not require extensive and expensive customization to accommodate the Company's current daily balancing and cash-out methodology.

Q. What is the Company's estimated cost for the replacement gas transportation management and billing system?

A. Based on quotations received for the identified system requirements, the Company estimates a five year total system cost of$1,259,549.

Q. Is the Company currently negotiating with a system provider on letter of intent which will describe the terms of precedent for entering into a contract for acquisition of the replacement gas transportation and billing system?

A. Yes.

Q. When does the Company plan on executing a contract with the system provider for acquisition of the replacement gas transportation management and billing system?

A. The Company plans on executing a contract with the system provider for the procurement of the replacement system following completion of a detailed requirements scoping process. The Company expects the scoping process to be completed by end of the fourth quarter of 2019.

Q. When will the Company be ready for system implementation and commissioning?

A. The Company believes the replacement system will be ready for implementation and commissioning during the fourth quarter of 2020.

Q. Will the Company provide notice and training to its Shippers, Marketers, and Pooling Agents in advance of implementation and Commissioning of the new system?

A. Yes. The Company anticipates providing its Shippers, Marketers, and Pooling agents with at least sixty days advanced notice and training for implementation and commissioning.

<u>Daily Balancing</u>

Q. Please explain why the Company is proposing to simplify its transportation service daily balancing methodology.

A. Since the Company was the first utility in Michigan to roll-out daily balancing to its transportation service customers, it did not have a good utility model at the time from which to draw upon for the design of its daily balancing methodology. As such, the Company based its original design on a complicated methodology once used by an interstate pipeline company to daily balance its interstate transportation service customers. In this filing, SEMCO Gas is proposing to simplify its daily balancing methodology because the Company believes its current methodology is unnecessarily complex making it difficult for the Company to manage and difficult for its Shippers, Marketers, and Pooling Agents to understand. Furthermore, the current daily balancing methodology is anticipated to be costly and burdensome to implement from a new software application development perspective.

Q. How is the Company proposing to modify the daily balancing methodology for its transportation service Shippers and Pools?

A. As shown on Sheets No. E-20 through E-22 of Exhibit A-31 (WEF-01), the Company is proposing to simplify its daily balancing methodology for its transportation service Shippers and Pools by eliminating the Company's complex firm balancing charge, interruptible balancing charge, excess balancing charge, and imbalance penalty charge from the Balancing Recovery Cost and replacing those charges with (i) a single and simple monthly Balancing Recovery Charge, (ii) eliminating cash-out of monthly imbalances and replacing it with cash-out of daily imbalances, (iii) pipeline penalty pass-through costs, and (iv) Unauthorized Use charges.

Q. Please explain why the Company plans to eliminate the firm balancing charge, interruptible balancing charge, excess balancing charge, and imbalance penalty charge.

A. Currently, the Company's daily Balancing Recovery Cost charges are comprised of a complex mix of charges including the firm balancing charge, interruptible balancing charge, excess balancing charge, and imbalance penalty charge. The purpose of these charges is to recover and credit the GCR cost of gas for certain GCR assets used to daily balance transportation service Shippers and Pools and to incentivize good gas management behaviors on behalf of Marketers and Pooling Agents. The Company has eliminated these mix of charges because they are unnecessarily complicated whereby a simpler methodology can be employed to achieve the same purpose of recovering the cost for use of the GCR's balancing assets and incentivizing good gas management behaviors. Furthermore, the Company's Shippers, Marketers, and Pooling Agents find the current balancing recovery cost charges difficult to understand, the Company finds them difficult to explain, and they are difficult to model and program from a billing system development perspective.

Q. What is the Company's purpose for implementing a single monthly Balancing Recovery Charge?

A. The purpose of implementing a single monthly Balancing Recovery Charge is to simplify the recovery the Company's allocated demand costs associated with its contracted storage, pipeline transportation, and no-notice services used to balance supply and demand of its Shippers.

Q. Will all revenue collected through the monthly balancing recovery charge be credited to the Company's Balancing and Demand portion of its cost of gas?

A. Yes.

Q. Will the monthly Balancing Recovery Charge serve to incentivize good gas supply management behaviors among Marketers and Pooling Agents as do the current balancing recovery cost charges?

A. No. As stated above, the purpose of the single monthly Balancing Recovery Charge is to simplify the recovery the Company's allocated demand costs associated with balancing supply and demand of its Shippers on a monthly basis. As will be described below, the Company's transition from monthly to daily cash-out of gas imbalances associated with Shippers and Pools will serve to incentivize good gas supply management behaviors among Marketers and Pooling Agents.

Q. Please describe how the Company's single monthly Balancing Recovery Charge will be assessed to the Company's Shipper's.

A. The Company will assess the single monthly Balancing Recovery Charge by multiplying the total actual monthly quantity of gas delivered to a Shipper by the Balancing Rate as shown on Sheet No. E-21 of Exhibit A-31 (WEF-01).

Q. Explain how the Balancing Recovery Rate developed.

A. Exhibit A-31 (WEF-01) shows the Company's annual no-notice, pipeline transportation, and storage demand costs applicable to balancing the Company's total supply and demand on the day. The total annual balancing demand cost was allocated to the Company's transportation Shippers and Pools based on the average and peak allocation supported by Witness Raab in Exhibit A-16, Schedule F-1. The Balancing Recovery Rate was calculated by dividing the resulting allocated annual demand cost by the Company's annual transportation service forecast quantity for calendar year 2020.

<u>**Daily Cash-Out**</u>

Q. What is the purpose of the Company's proposal to transition from monthly to Daily Cash-Out of gas imbalances for the Company's transportation service Shippers and Pools?

A. The purpose of Daily Cash-Out of transportation Shipper and Pool gas imbalances serves to (i) incentivize good gas supply management behaviors among Marketers and Pooling Agents who supply gas to SEMCO's Shippers and Pools, and (ii) restrict access of Shippers and Pools to the Company's limited on-system storage assets.

Q. Explain why the Company is eliminating monthly cash-out of Shipper monthly imbalances and replacing it with Daily Cash-Out of daily gas imbalances held by the Company's transportation service Shippers and Pools?

A. Under the Company's current tariff, monthly gas imbalances of less than 5% are rolled over to the next month and monthly gas imbalances greater than 5% are cash-out. Monthly gas imbalances that are carried over to the next month (i) require the Company to track such imbalances on its books, (ii) occupy working gas inventory space in the Company's on-system storage assets that could otherwise be utilized by SEMCO Gas's GCR customers, and (iii) results in a higher level of on-system storage inventory carrying costs. In other words, the tracking of transportation service imbalances from month to month provides an unnecessary level of complexity that can be simplified through the implementation of a Daily Cash-Out methodology. Furthermore, the Company believes good gas supply management behaviors, among Marketers and Pooling Agents, will be further incentivized through the implementation of a Daily Cash-Out methodology.

Q. Please describe the Company's daily cash-out charge.

A. The Company's Daily Cash-Out methodology is shown on Exhibit A-33 (WEF-03) and described in detail on Sheet Nos. E-20 to E-21 of Exhibit A-31 (WEF-01). Daily Cash-Out can result in either a charge or a credit to a Shipper or a Pool depending on the direction of the daily imbalance.

Q. Explain the daily cash-out when a Shipper's or Pool's Daily Imbalance is negative.

A. When the daily imbalance is negative, the Shipper or Pool must purchase gas from the Company to resolve the imbalance. The gas purchase price paid by the Shipper or Pool to the Company depends on whether or not the Negative Imbalance is authorized or unauthorized. The authorized portion of a Shipper's or Pool's Negative Imbalance is the quantity of the Negative Imbalance that is less than or equal to the Company's Daily Balancing Tolerance in effect on the day. The unauthorized portion of a Shipper's or Pool's Negative Imbalance is the quantity of the Negative Imbalance that is greater than the Company's Daily Balancing Tolerance in effect on the day. The Shipper or Pool's purchase price for the authorized portion of the Negative Imbalance gas will be the greater of the Company's currently effective commodity GCR rate or the effective daily index price (explained below) on the day of the sale. The Shipper or Pool's purchase price for the unauthorized portion of the Negative Imbalance gas will be the greater of the Company's currently effective commodity GCR rate or the effective daily index price on the day of the sale plus $10.00.

Q. Explain the Daily Cash-Out when a Shipper's or Pool's Daily Imbalance is positive.

A. When the Daily Imbalance is positive, the Company must purchase gas from the Shipper or Pool to resolve the imbalance. The gas purchase price paid by the Company to the Shipper or Pool depends on whether or not the Positive Imbalance is authorized or unauthorized. The authorized portion of a Shipper's or Pool's Positive Imbalance is the quantity of the Positive Imbalance that is less than or equal to the Company's Daily Balancing Tolerance in effect on the day. The unauthorized portion of a Shipper's or Pool's Positive Imbalance is the quantity of the Positive Imbalance that is greater than the Company's Daily Balancing Tolerance in effect on the day. The Company's purchase price for the authorized portion of the Positive Imbalance gas will be the lesser of the Company's currently effective commodity GCR rate or the effective daily index price (explained below) on the day of the sale. The Company's purchase price for the unauthorized portion of the Positive Imbalance gas will be 50% of the Company's currently effective commodity GCR rate or the effective daily index price on the sale, whichever is lower.

Q. Please explain the effective Daily Index Price.

A. The effective Daily Index Price will be the daily average of the MichCon city-gate midpoint price and the Consumers city-gate midpoint price as published in Platts Gas Daily.

Q. How will Daily Cash-Out charges and credits be billed to a Shipper or a Pool?

A. The accumulated net total charges and credits for Daily Cash-Outs over the effective billing period will be billed to the Shipper or Pool Agent on a monthly basis.

Q. Is Unauthorized Use of gas by a Shipper different from Unauthorized Negative Imbalances and Unauthorized Positive Imbalances?

A. Yes. As explained, the unauthorized portion of a Shipper's or Pool's Negative Imbalance or Positive Imbalance is the quantity of the Negative Imbalance or Positive Imbalance that is greater than the Company's Daily Balancing Tolerance in effect on a day. An

Unauthorized Use of gas is any gas consumed by a Shipper in excess of the quantities authorized by the Company during the period when a Curtailment has been instituted pursuant to Rule C3.2 of the Company's tariff.

Q. In addition to Daily Cash-Out charges, are Shippers subject to Unauthorized Use Charges when gas is consumed in excess of the quantity authorized by the Company during a period of curtailment?

A. Yes. Unauthorized Use of gas by a Shipper during a period of curtailment shall be charged in accordance with the Company's Unauthorized Use Charge provisions as described in Rule C3.2 of the Company's tariff.

<u>**Wireless Telecommunications Technology**</u>

Q. Is the Company in the process of converting its Transportation Shippers' specialized metering equipment from utilizing dedicated analog phone lines to wireless communications technology?

A. Yes. As shown on Sheet No. E-14 of Exhibit A-31 (WEF-01), the Company may utilize wireless communications technology for remotely communicating with its Transportation Shipper's specialized metering equipment.

Q. Explain why the Company is converting its Transportation Shippers' specialized metering equipment from dedicated analog phone lines to wireless communications technology?

A. The Company currently requires all Shippers to provide a dedicated active analog telephone line so the Company can remotely read its specialized metering equipment on a daily basis. As an option, the Company currently allows a Shipper to waive the dedicated active analog telephone line requirement if the Shipper agrees to reimburse the Company $35.00 per month for SEMCO Gas's installation of an alternate communication option. For those Shippers that have chosen to accept the $35.00 per month alternate communication option, the Company has installed wireless telecommunications technology at the Shipper's meter site. In this filing, the Company is proposing to eliminate the dedicated active analog telephone line requirement as a result of the planned future phase-out of new analog telephone line installations by Michigan's telecommunications providers. As a result of the planned phase out of analog telephone line installations, the Company plans to convert all of its remaining analog phone line enabled specialized metering equipment to wireless communications technology over a five year period beginning 2019.

Q. Does the Company have a solution for a Shipper's meter site where wireless communications technology or an alternative communications technology is unavailable or will not operate reliably?

A. No. For a Shipper's meter site, where a wireless communications technology or where an alternative communications technology is unavailable or will not operate reliably, the Shipper shall not be eligible for transportation services.

Q. Is the Company proposing to charge all transportation service Shippers $35.00 per month for ongoing wireless telecommunications costs in addition to the Company's Remote Meter Charge?

A. No. The Company's ongoing costs for daily remote meter reading, including the costs for wireless telecommunications, will be recovered through the Company's Remote Meter Charge shown on Sheet No. E-20 of Exhibit A-31 (WEF-01).

Q. Please explain the Company's Remote Meter Charge.

A. All Shippers are charged a monthly flat Remote Meter Charge of $75.00. The purpose of the Remote Meter Charge is to recover the ongoing costs of operating and maintaining the Company's special metering equipment used to record and gather daily meter reads from Shippers.

<u>Gas Quality Specifications</u>

Q. Please explain the Company's gas quality specifications.

A. The Company's gas quality specifications are shown on Sheet No. E-7 of Exhibit A-31 (WEF-01). All gas received from a Shipper, when sourced from an interstate or intrastate pipeline and delivered to the Company's system shall be merchantable and conform to the specifications listed.

Q. What will be the gas quality specifications when gas is received from a Shipper and sourced directly from a non-interstate or non-intrastate source?

A. For gas received from a Shipper, when such gas is sourced directly from an underground production reservoir, landfill, bio-gas generator, or other gas production facility and delivered directly to the Company's system, the gas shall be merchantable and conform to the gas quality specifications as described in a specific operation and maintenance agreement negotiated between the Company and the gas producer thereof. Compliance with the gas quality specifications for such sources of gas shall be based on an actual gas sample and subsequent laboratory analysis performed by a certified third party.

Q. Explain how the gas quality specifications were developed.

A. The gas quality specifications were developed by benchmarking other Michigan utility company's gas quality standards, adopting best practices recommended by the American Gas Association, and utilizing applicable gas quality requirements as described in Michigan's Technical Standards for Gas Service.

<u>**Facility Improvement Demand Charge**</u>

Q. What is the Company's purpose for implementing the Facility Improvement Demand ("FID") Surcharge?

A. In the Company's Act 9 filing for authorization to construct the Marquette Connector Pipeline, Case No. U-18202, the Commission approved the settlement agreement between the Company and all the intervening parties to the case in August 2017. The approved settlement agreement requires the Company to "spread the interconnect costs paid to GLGTC and NNG over a minimum period of five (5) years to be collected through the balance and demand charge of the GCR mechanism. SEMCO Gas will seek to revise its transportation balancing charges in the next general rate case to include an applicable portion of the total interconnect costs which shall be refunded to the balance and demand costs of the GCR mechanism." The purpose of the FID Surcharge, as shown on Sheet No. E-24 of Exhibit A-31 (WEF-01) is to recover the allocated Great Lakes Gas Transmission Company ("GLGTC") and Northern Natural Gas ("NNG") interconnection costs from the Company's transportation Shippers and refund those costs to the Company's GCR and GCC customers through the Balance and Demand cost rate associated with the GCR mechanism.

Q. What is the total estimated cost of the MCP GLGTC and NNG interconnections?

A. GLGTC's and NNG's total estimated MCP interconnection costs are approximately $10,262,775.

Q. Explain how the FID Rate was calculated.

A. Exhibit A-34 (WEF-04) shows how the FID Surcharge rate was calculated. GLGTC's and NNG's total estimated MCP interconnection cost was allocated to the Company's transportation Shippers and Pools based on the average and peak allocation supported by Witness Raab in Exhibit A-16, Schedule F-1. The FID Surcharge rate was calculated by dividing the resulting allocated annual MCP interconnection cost by the Company's annual transportation service forecast quantity for each calendar year.

Q. How much of the total estimated MCP interconnection cost will be recovered from Transportation Shippers and credited to the Balancing and Demand portion of the Company's GCR cost of gas over a five year period?

A. As shown in Exhibit A-34 (WEF-04), the Company will credit approximately $2,668,820 to the Balancing and Demand portion of the Company's GCR cost of gas over a five year period beginning with the first billing month following the Company's receipt of an order from the Commission.

Q. Explain how the FID Surcharge will be calculated and billed to each transportation service Shipper.

A. The FID Surcharge will be billed monthly by applying the FID Rate to each Shipper's actual delivered quantity of gas during the each monthly billing period.

<u>**New Tariff Language**</u>

Q. Please itemize the new language included under the "Possession of Gas" section found on Sheet Nos. E-4 to E-5 of Exhibit A-31 (WEF-01) and explain why those topics have been included.

A. The Company has included new language on topics that discuss (i) indemnification of the Company, (ii) warranty, (iii) non-waiver of future defaults, (iv) incorporation of rate schedules and contract, (v) assignment, (vi) default, and (vii) bankruptcy. These topics have been included so the Company and its Shippers, Marketers, and Pool Agents will have a shared understating of these topics as they apply to the Company's rules and regulations for gas transportation service.

Q. Does the inclusion of the new tariff language in Section E of the Company's Tariff simplify the Company's proforma Transportation Service Agreement?

A. Yes. Inclusion of the new legal language topics in Section E of the Company's tariff simplifies the Company's Transportation Service Agreement so the language can be now be included by reference rather than depicted in detail in the Company's proforma Transportation Service Agreement.

<u>**Off-System Transportation Service**</u>

Q. Is the Company proposing to revise the Tariff language for its Off-System Transportation Service "OSTS"?

A. Yes.

Q. Describe the characteristics of service for the Company's OSTS.

A. Under the OSTS rate schedule, as revised, the Company will transport gas from an OSTS Shipper's Point of Receipt to a Point of Delivery up to the OSTS Shipper's Maximum Delivery Quantity ('"MDQ") on a firm basis, or on an interruptible basis if firm capacity is not available, utilizing the Company's utility pipeline system. The Company's utility pipeline distribution system, including OSTS Shipper's Point of Receipt and Point of Delivery, must have adequate flow capacity. In addition, the OSTS Shipper's Point of Receipt and Point of Delivery must provide adequate pressure differentials to allow the flow of gas unless the OSTS is capable of being performed on a displacement basis. The Company's OSTS is subject to the Company's Curtailment of Gas Service provisions (Rule C3).

Q. Please summarize the material revisions and updates to the Company's OSTS.

A. The material revisions and updates to the Company's OSTS include:

- The Company's utilization of wireless communications technology for communication or an alternative communications technology with the Company's OSTS Shipper's specialized metering equipment.
- An allowance for an OSTS Shipper to install additional equipment at OSTS Shipper's expense to allow OSTS Shipper or Shipper's Authorized Agent to

remotely monitor OSTS Shipper's gas flow. The Company also requires that installation of remote monitoring equipment be performed by the Company or under direct on-site supervision by the Company.

- A requirement that all gas received from an OSTS Shipper and delivered to the Company's system be merchantable and conform to the Company's gas quality specifications as described in Rule E.3.
- An Operational Balancing Agreement ("OBA") requirement whereby the OBA shall describe the terms of balancing, balancing charges, and penalty charges.
- A requirement that the Company must have adequate System Capacity to accommodate OSTS Shipper's MDQ and that availability of System Capacity for OSTS shall be secondary to the System Capacity requirements necessary to serve the Company's Residential and General Service class customers.
- A requirement that all OSTS Shippers provide the Company with daily gas Nominations via the Company's electronic gas nominating system.
- Inclusion of an OSTS Transportation Rate that can be demand or volumetric based.

Transportation Service Proforma Agreements

Q. Has the Company revised and updated the proforma agreements utilized in conjunction with its Rules and Regulations for Transportation Service?

A. Yes. As shown in Exhibit A-35 (WEF-05), the Company has revised, updated, and simplified the Transportation Service Agreement used to establish the terms and conditions of Transportation Service between the Company and its Transportation Shippers. In addition, as shown in Exhibit A-36 (WEF-06), the Company has also revised and updated the Pooling Agreement used to establish the terms and conditions of Pooling between the Company and its Shippers' Pooling Agents.

Q. Has the Company developed any new proforma agreements utilized in conjunction with its Rules and Regulations for Transportation Service?

A. Yes. As shown in Exhibit A-37 (WEF-07), the Company has developed an agreement for Shippers who choose to aggregate non-transportation service accounts under a principle account as described on Sheet Nos. E-10and E-11 of Exhibit A-31 (WEF-01). The

Account Aggregation Agreement replaces the former Aggregation of Accounts Option Attachment B associated with the Company's prior Transportation Service Agreement. The Company has also developed an Off-system Transportation Service Agreement as shown in Exhibit A-38 (WEF-08). The Off-system Transportation Service Agreement will be used to establish the terms and conditions for off-system transportation service between the Company and its OSTS Shippers. Lastly, the Company has developed an Operational Balancing Agreement as shown in Exhibit A-39 (WEF-09). This agreement will be utilized for all of the Company's OSTS Shippers. The Operational Balancing Agreement will establish specific terms and conditions for balancing supply and consumption between a Shipper and the Company or the specific terms and conditions for balancing on-system receipts and off-system deliveries of gas between an OSTS Shipper and the Company.

Gas Customer Choice Program, Revisions, and Updates

Gas Customer Choice Overview

Q. Please provide an overview of the Company's GCC program.

A. Under SEMCO Gas's voluntary GCC program, retail customers have the option to purchase their natural gas supply from an Alternative Gas Supplier ("AGS" or "Supplier"). GCC customers continue to be physically served by SEMCO Gas and pay the applicable distribution charges, the same as the GCR customers do. SEMCO Gas maintains the same responsibilities for both GCC and GCR customers. Each MPSC licensed AGS participating in the Company's GCC program establishes Supplier-designated pricing pools into which it enrolls its customers. Each month a Daily Delivery Obligation for each pricing pool is provided to the Supplier which specifies the quantity of gas to be delivered to the Company. The Company, under a buy-sell process, purchases the gas from the Supplier for each individual pricing pool, at the Supplier-designated price and resells the gas at the same pool price to the GCC customer. At the conclusion of each April-March annual term, a reconciliation is performed for each Supplier pricing pool, providing a true-up of gas quantities and dollars.

Section F Revisions and Updates

Q. Is the Company proposing changes to its GCC tariff in this case?

A. Yes. Through review of its own GCC program, and those of Consumers Energy and DTE Gas Company, SEMCO Gas has made changes to its GCC tariff to improve the administration of the program, simplify the process for AGS that participate in the program, and create a more efficient program overall. With the implementation of these changes, SEMCO Gas's GCC program will more closely reflect the GCC programs of the aforementioned utilities.

Q. Is the Company providing revised tariff sheets reflecting its GCC tariff changes?

A. Yes. Exhibit A-16 (JLD-7), Schedule F5 supported by Witness Dennis contains a clean version of the GCC tariff reflecting the GCC tariff changes, as well a red-line version accepting the revisions.

Q. What changes are being made?

A. Suppliers participating in the GCC program set up pools in which to enroll customers, referred to as pricing pools. Each pricing pool has a specified rate, designated by the Supplier, at which all customers in the pool are billed. The Company is proposing to adopt the process of other utilities in Michigan regarding the aggregation of pricing pool activity to improve the efficiency of its GCC program.

Q. Please discuss the impact of the changes related to aggregation of pricing pools on the Daily Delivery Obligation ("DDO") process.

A. Under the existing tariff, DDOs are determined and provided to the Supplier with a separate DDO for each pricing pool. Whether a Supplier has two pools or 100 pools, each pricing pool has an associated DDO which must be specifically nominated to the Company. This process is administratively burdensome for the Supplier, and requires the Company to monitor and confirm each of the Supplier's nominations by price pool, and determine if there are discrepancies which may result in the assessment of Failure Fees. As shown in Section No. F1.6 on Sheet F-3 of Exhibit A-16 (JLF-7), Schedule F5, the Company is proposing the determination of the DDO on an aggregate basis for all accounts served by the Supplier. In other words, all Supplier-designated pricing pools will be combined for the determination of the DDO. The aggregation of the pricing pools for the DDO will reduce the number of nominations the Supplier is required to make and track, as well as reducing the Company's processing time for confirming nominations and determining discrepancies.

Q. Will imbalances be aggregated as well?

A. Yes. With the aggregation of pricing pools for DDO's, imbalances will be managed at the Supplier level, rather than the pool level. It is expected that managing imbalances on the Supplier level will allow for easier assessment of the GCC imbalance activity.

Q. How will the aggregation of pricing pools affect Supplier remittances?

A. As shown in Section F1.9 on Sheet No. F-3 of Exhibit A-16 (JLF-7), Schedule F5, the Company will use the average actual price billed to the GCC customer for calculating the Supplier remittance each month and a cap on the remittance price of 110% of the cost of gas billed to sales customers. This is the same methodology that has been in effect for the GCC tariffs of DTE Energy and Consumers Energy for several years.

Q. Is the Company proposing changes related to the annual reconciliation?

A. Yes. As shown in Section F1.10 on Sheet No. F-4 of Exhibit A-16 (JLF-7), Schedule F5, the reconciliation will be revised to reflect the aggregation of pricing pools. In addition, the Company has added language to clarify when a reconciliation occurs. Currently the tariff specifies a reconciliation will occur at the end of the March cycle or upon revocation of a Supplier's Authorized Supplier status. The Company has added language addressing the voluntary withdrawal by a Supplier from the GCC program.

Q. Is the Company recommending changes to other areas of the GCC tariff?

A. Yes. As shown in Section F1.5 on Sheet No. F-2 of Exhibit A-16 (JLF-7), Schedule F5, and The Company is also proposing the ability to close inactive pricing pools and clarification of other GCC related items.

Q. Is a Supplier limited in the number of pricing pools it may have?

A. No. Suppliers may have as many pools as desired and are assessed a $100/price pool Administrative Fee. The Company is proposing, however, that price pools that have remained inactive for six months or longer may be closed.

Q. Why is the Company proposing to close inactive price pools?

A. It has been SEMCO's experience that some AGS on their system are opening price pools in anticipation of having customers in the future, but then not enrolling any customers in the new pools. It may be that an existing pool can be utilized at a new rate, and, if so, that is preferable to opening a pool that may never be used. Each pricing pool is assigned an account number through SEMCO's customer billing system. To maintain historical records, price pool account numbers can only be assigned and used one time. Therefore, the Company wants to encourage Suppliers to consider if an existing pool may be utilized at a new rate, and to ensure they have customers to enroll before opening a new price pool. The reduction in open pricing pools can also save unnecessary pooling fees for the AGS for pools they are not utilizing.

Q. Is the Company proposing a change related to Failure Fees?

A. Yes. With the aggregation of pricing pool processes, Failure Fees will be determined based on the delivery of the aggregate DDO, rather than by each individual pricing pool.

Q. What are the remaining changes to the Company's GCC Tariff?

A. The Company is proposing changes to: (i) its Supplier nomination language to remove the reference of the designated price category, and the Gas Transportation Services Department, (ii) in the area of Customer Billing, the Company is removing language related to the allocation of supply among pricing pools in the event of an over-delivery of supply, which is no longer necessary with the aggregation of the DDO, (iii) the removal of the reference to Operational Flow Orders and replacing it with referral to the Company's Curtailment rules. In addition, the definitions which are currently existing throughout the GCC tariff will be consolidated into one area under the heading DEFINITIONS.

<u>Cost of Gas Forecast</u>

Q. Why has the Company calculated a commodity cost of gas rate forecast in this case?

A. The commodity cost of gas rate is used by several of SEMCO Gas's witnesses for several purposes including determining the costs of company use gas, lost and unaccounted for gas, gas-in-kind, gas in storage.

Q. What is SEMCO Gas's projected commodity cost of gas rate for the projected 2020 test year?

A. For the January 2020 through December 2020 test year, SEMCO's project commodity cost of gas rate is $2.6781 per Dth, as show in Exhibit A-40 (WEF-10).

Q. How was the commodity cost of gas rate calculate the projected 2020 test year?

A. Using the Company's GCR plan for the five year period beginning April 1, 2019 (Case No. U-20245) the Company's forecasted monthly supply purchases were priced at the NYMEX-based market price forecast and adjusted for the applicable basis value for each month of the plan covering the 2020 annual period.

Q. How was the NYMEX-based market price forecast determined and what annual average value for the projected 2020 test year was used to determine the Company's estimated commodity cost of gas?

A. The NYMEX-based market price forecast is determined from the average of the NYMEX futures settlement prices for the five natural gas market trading days beginning March 1, 2019. The annual average of the NYMEX based values used to determine the Company's estimated commodity cost of gas was $2.7695.

<u>**Working Capital Adjustment for Gas Stored**</u>

Q. Please explain Exhibit A-41 (WEF-11), Working Capital Adjustment for Gas Stored Underground.

A. Exhibit A-41 (WEF-11), shows the projected working capital impact to the cost of gas stored underground for 2018 compared to the cost of gas stored underground in 2020. During 2018, SEMCO Gas had a combined 13-month average balance of gas stored underground of 9,358,774 Dth (see Column (A)) at a combined 13-month average cost of $25,003,134 (see Column (C)). Column (D) shows that the anticipated 2020 13-month average balance of gas in storage will be 11,573,954 Dth. The 2020 13-month average is based on the storage estimates included in the Company's 2019-2020 GCR plan in Case No. U-20245. The cost of the 2020 13-month average gas in storage is projected to be $29,452,373 or an increase of $4,449,240.

Q. What factors explain the increase of the 2020 13-month average cost of gas in storage?

A. The increase of the 13-month average cost of gas in storage ($4,449,240) is the result of the projected higher average cost of gas in storage and a higher average storage volume for the 13-month 2020 annual period compared the 13-month 2018 annual period. The higher average storage volume is primarily attributable to the Company's acquisition of an incremental 1.5 MMDth off-system storage service beginning April 1, 2019.

Q. Does this conclude your prefiled 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 increase its rates for the	)	Case No. U-20479
distribution and transportation of natural gas	)	
and for other relief.	)	

DIRECT TESTIMONY AND EXHIBITS OF PAUL RAAB

ON BEHALF OF

SEMCO ENERGY GAS COMPANY

May 31, 2019

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul H. Raab and my business address is 5313 Portsmouth Road, Bethesda, MD 20816. I am an independent economic consultant.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of SEMCO Energy Gas Company ("SEMCO Gas" or "Company").

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for my entire career, having assisted electric, gas, telephone and water utilities; commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My areas of focus are planning issues, costing and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE COMMISSIONS IN REGULATORY PROCEEDINGS?

A. Yes. I have previously provided expert testimony before the Michigan Public Service Commission ("Commission" or "MPSC") in Case Nos. U-6949, U-13575, and U-16169 as well as the state regulatory authorities of Alaska, the District of Columbia, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Missouri, Montana, Nebraska, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and

Wisconsin. In addition, I have presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee, the Province of Saskatchewan, and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Attachment A to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. There are three main purposes for my testimony. First, I sponsor the Company's weather normalization adjustment, which adjusts test year volumes and revenues for normal weather. Next, I sponsor the throughput and customer forecast that forms the basis for the Company's forecasted test year. Finally, I sponsor the Company's class cost of service study. This study is used to guide the Company in assigning the required revenue increase across customer classes and in designing rates.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor the following exhibits:

Exhibit A-5 (PAR-1), Schedule E-1	Annual Sales Data by Major Customer Classes and System Output
Exhibit A-5 (PAR-2), Schedule E-2	Annual Customer Data by Major Customer Classes
Exhibit A-5 (PAR-3), Schedule E-3	Weather Adjustment by Major Customer Classes
Exhibit A-15 (PAR-4), Schedule E-1	Projected Sales Data by Major Customer Classes
Exhibit A-15 (PAR-5), Schedule E-2	Projected Customer Data by Major Customer Classes
Exhibit A-15 (PAR-6), Schedule E-3	Forecasted Billing Determinant Detail
Exhibit A-16 (PAR-7), Schedule F-1	Projected Cost of Service Allocation Study

The above-designated exhibits were prepared by me or under my direction and supervision.

Q. PLEASE DESCRIBE THE BILLING DETERMINANT ADJUSTMENTS THAT YOU ARE SPONSORING.

A. I sponsor two adjustments in this case: (1) a weather normalization adjustment and (2) an adjustment to reflect forecasted billing determinants. The weather normalization adjustment adjusts test year volumes and revenues for normal weather. My specific adjustment for normal weather is provided in the first section of this portion of my testimony. Since the Company is using a forecasted test year in this case, a forecast of billing determinants is required

Weather Normalization Adjustment

Q. PLEASE EXPLAIN THE PROCEDURE USED TO MAKE THE WEATHER ADJUSTMENT.

A. There are a variety of methods that can be used to make this adjustment. In this case, I adhered to the following five guidelines:

1. The method employs a level of rate class disaggregation that is as fine as can be reasonably supported by the data.

2. The method employs as many weather recording stations as can be reasonably supported by the data.

3. "Normal" weather is based on a fifteen-year average, consistent with Commission precedent.

4. Regression techniques are used to relate usage to the appropriate weather variable. These regression equations are as free as possible from any identifiable statistical impairment.

5. The weather variable employed in the regression specifications is reasonably anticipated to influence usage. A Heating Degree-Day ("HDD") is a measure of the number of degrees by which the average daily temperature falls below 65 degrees Fahrenheit on any given day. The sum of these daily degree-days over any given period is a measure of the amount of heating needed over that period. Therefore, HDDs are used to normalize those classes that use natural gas for space heating purposes.

Q. HOW DID YOU IMPLEMENT THESE GUIDELINES?

A. The Company maintains historical consumption records for customers who are served under one of the Company's tariffed rates (Residential, GS-1, GS-2, GS-3, TR-1, TR-2 and TR-3). Usage for these customers is initially assumed to be weather-sensitive and should therefore be weather-normalized for purposes of developing the revenue deficiency and required rates in this case. For these customer classes, I relate usage per customer to a weighted HDD variable, where the weights I use are based on the volumes by division. I develop ten separate usage/customer regressions for weather normalization purposes (one for each of the seven classes identified above, plus the three transportation classes within GS-1, GS-2 and GS-3).

To calculate the weather adjustment from these equations, the appropriate normal number of HDDs is applied to the corresponding regression equation to obtain the sales that would have occurred had customers experienced normal weather. These volumes are priced at existing rates and the resulting adjustment represents the difference between the weather normalized revenues and the actual test year revenues.

Q. WHAT IS THE SOURCE OF YOUR USAGE AND CUSTOMER DATA?

A. The source of the usage and customer data is the Company. SEMCO Gas's unadjusted total 2018 distribution volumes are 67,842,899 Dth, as shown on Exhibit A-5 (PAR-1), Schedule E-1. This is comprised of 63,371,856 Dth of volumes delivered under tariffed rate schedules and 4,471,043 Dth delivered under special contracts. Only those volumes delivered under tariffed rate schedules are weather normalized.

On average for 2018, SEMCO Gas had approximately 306 thousand customers served under a tariffed rate schedule, and 6 non-tariffed (special contract) customers, as shown on Exhibit A-5 (PAR-2), Schedule E-2.

Q. PLEASE DESCRIBE THE REGRESSION EQUATIONS THAT YOU USED TO DEVELOP THE RELATIONSHIP BETWEEN USAGE AND THE APPROPRIATE WEATHER MEASURE.

A. Regression analysis develops the relationship between a dependent variable and one or more independent variables. In this case, the dependent variable is the monthly gas usage of SEMCO

Gas's customers. The independent variables are the weather effects (HDDs) and any trend observed in the usage per customer data. Thus, the regression equations estimated for this purpose quantify the sensitivity of gas usage to changes in the weather.

The regression equation is specified as:

$$Usage_{i,t} = \alpha_i + \beta_{1,i}(HDD_t) + \beta_{2,i}(TREND_t) + \varepsilon_{i,t}$$

where:

$Usage_{i,t}$ = Dth gas usage per customer per month for rate class i ;

HDD_t = the actual monthly HDDs;

$TREND_t$ = a trend variable (January 2014=1);

$\varepsilon_{i,t}$ = an error term; and

$\alpha_i, \beta_{1,i}, \beta_{2,i}$ = estimated coefficients for tariff class i.

In this case, the $\beta_{1,i}$ coefficients can be used to estimate what consumption would have been had weather been "normal."

Q. WAS THERE A CORRESPONDING WEATHER ADJUSTMENT TO THE CONSUMPTION IN EACH OF THESE WEATHER STATION/RATE CODE GROUPINGS?

A. No. It was not possible to develop a meaningful relationship between usage and weather for the customers served under the TR-3 tariff, due to an observed lack of weather sensitivity. Thus, for this class, observed volumes are assumed to equal weather normalized volumes for the historical test year.

Q. WHAT WERE YOUR CRITERIA FOR DETERMINING THE VALIDITY OF THE ESTIMATED RELATIONSHIP?

A. I relied on a battery of commonly applied statistical tests. These tests include:

1. t-test. The t-test is used to determine whether an independent variable (in this case, weather) has an influence on the dependent variable (in this case, usage per customer). In other words, it determines whether the selected variable belongs in the regression.

2. R-squared. This is a measure of the success of the regression in predicting the values of the dependent variable within the sample.

3. Log likelihood test. This is the value of the log likelihood function (assuming normally distributed errors) evaluated at the values of the coefficients. It is often used to select between alternative regression specifications.

4. Durbin-Watson statistic. The Durbin-Watson statistic tests for first-order autocorrelation in the errors, which is the situation where the regression error in one period moves together with the regression error of another. When errors exhibit autocorrelation, the estimated coefficients are biased.

5. F-statistic. This statistic tests whether all the coefficients in a regression are zero. In other words, it tests for the statistical significance of the regression itself.

Q. HOW DID YOU APPLY THESE TESTS TO YOUR REGRESSION EQUATIONS?

A. I initially used a basic statistical technique called the Ordinary Least Squares ("OLS") method to estimate the coefficients of the specified regressions in those cases where enough data exist to derive meaningful statistics. I then examined the regression results to determine whether a correction for autocorrelation was needed. If the need for a correction was indicated, I applied an AutoRegressive Moving Average ("ARMA") estimation technique to estimate the coefficients. After introduction of the ARMA terms, I re-tested the models. After successfully passing these tests, I knew that the weather coefficients that I had estimated were unbiased and of minimum variance, and I proceeded to test whether a valid statistical relationship exists between the dependent and independent variables. For this purpose, I relied primarily on the t-test, the R-squared, the log likelihood test, and the F-test.

Q. UNDER WHAT CIRCUMSTANCES WAS A REGRESSION EQUATION REJECTED USING YOUR TESTING CRITERIA?

A. As an overview, I performed all statistical tests at the commonly applied 95% level of confidence. I did not reject any regression equation if it did not pass the initial tests for serial correlation, but rather used the information from those tests to reduce the serial correlation as much as possible before moving on to tests of the coefficients themselves. In this way, I was able to derive a statistically valid weather normalization adjustment for all the classes for which enough data exist.

Q. HOW ARE THE HEAT SENSITIVE FACTORS THAT YOU DERIVE INTERPRETED?

A. As an example, consider the results obtained for SEMCO Gas's residential customers. The regression I performed for consumption of these customers yields an estimate for the HDD coefficient of 0.013192. This means that if the average daily temperature were lower by one degree, one would expect residential consumers to respond to that lower temperature by using approximately 0.13 more therms of natural gas per customer on that day. Conversely, if the average temperature were one degree higher, then residential consumers would use approximately .13 less therms of natural gas per customer.

Q. YOU STATED EARLIER THAT THE ESTIMATED $\beta_{1,i,j}$ COEFFICIENTS CAN BE USED TO ESTIMATE WHAT CONSUMPTION WOULD HAVE BEEN HAD WEATHER BEEN NORMAL. EXACTLY HOW IS THIS DONE?

A. This is done by using the monthly departure from normal and the regression coefficients. The adjustment formula for the regression equation is:

WNA = (HDD departure) * (HDD Coeff) * Customers

Q. HOW ARE THE DEPARTURES CALCULATED?

A. Departures, which measure how the test year weather differs from "normal" weather, are calculated by subtracting the actual monthly weather variables for the test year from the normal monthly weather variables for those months. The normal monthly HDDs are calculated as the 15-year average over the period January 2004 to December 2018.

Q. HOW DID YOU COMPUTE THE LEVEL OF REVENUES ASSOCIATED WITH THESE VOLUMETRIC ADJUSTMENTS?

A. I multiplied the volumetric adjustment from above by the appropriate delivery fee.

Q. AFTER APPLYING THE ABOVE FORMULAS, WHAT ARE THE RECOMMENDED WEATHER NORMALIZATION ADJUSTMENTS TO THE COMPANY'S TEST YEAR ACTUAL NATURAL GAS SALES?

A. As shown in Exhibit A-5 (PAR-3), Schedule E-3, the adjustment results in a decrease in the Company's actual test year natural gas sales volumes of 1,703,388 Dths.

Customer and Volume Forecast

Q. WHY IS IT NECESSARY TO DEVELOP A FORECAST OF THE NUMBER OF CUSTOMERS AND WEATHER-NORMALIZED VOLUMES?

A. The Company is proposing to change rates on a forward-looking test year. As a result, it is necessary to develop a forecast of customers and normal weather volumes.

Q. HOW DID YOU DO THIS?

A. I utilized the same breakdown of customer classes that were used to develop the weather normalization adjustment in the prior section, and I projected usage per customer based on the same regression equations that were used to weather normalize volumes. I also developed separate regression equations to project the number of customers for each of these customer groupings. The product of the projected usage per customer and the number of customers yielded the forecast of volumes by customer grouping, which were summed to produce a forecast of SEMCO Gas firm sales. The results of this process are summarized on Exhibit A-15 (PAR-4), Schedule E-1 and Exhibit A-15 (PAR-5), Schedule E-2.

Q. PLEASE EXPLAIN EXHIBIT A-15 (PAR-4), SCHEDULE E-1 AND EXHIBIT A-15 (PAR-5), SCHEDULE E-2.

A. These exhibits summarize the forecast of delivered volumes and customers, respectively, for the future test year, 2020. As shown on these exhibits, based on recent trends, I project that SEMCO's delivered volumes and customers served will both increase over the forecast period.

Q. YOU INDICATE ABOVE THAT YOUR FORECASTS ARE BASED ON RECENT TRENDS. HAVE YOU DONE ANY RESEARCH TO CONFIRM THAT THESE TRENDS CAN BE PROJECTED TO CONTINUE FOR THE NEXT TWO YEARS?

A. Yes, I have examined four recent forecasts of economic activity for Michigan. These forecasts are:

1. The Southeast Michigan Council of Governments ("SEMCOG") 2045 Regional Development Forecast by Watershed prepared in November 2018.
2. The SEMCOG 2045 Forecast Population by Age Group by School District prepared in October 2018.
3. The forecast documented in Economic Outlook and Revenue Estimates for Michigan prepared by the Michigan House Fiscal Agency in May 2018.
4. The forecast of the Research Seminar in Quantitative Economics ("RSQE") at the University of Michigan, released on November 16, 2018.

Q. PLEASE DISCUSS THE NOVEMBER 2018 SEMCOG FORECAST.

A. This forecast reflects modestly increasing economic activity over the period 2015–2045, as reflected in population, household and job growth. Population is expected to grow in the Southeast Michigan Region from 4,722,764 in 2015 to 4,823,101 (2.1%) in 2025. The number of households is forecasted to grow in the region by 90,204 (from 1,862,504 to 1,952,708, or 4.8%) over the period from 2015 to 2025. Similarly, jobs are expected to grow over this same period in the region by 88,488 jobs (2,774,223 in 2015 to 2,862,711 in 2025, 3.2%).

The SEMCOG 2045 Forecast Population by Age Group by School District underscores these modest improvements in economic activity. With respect to population, that report states:

> While the decline in school-age population will slow down and stabilize in the coming decades, the changes among individual ages will continue to transform our schools. During the past decade, the region witnessed a dramatic decline in elementary school-age children (Figure 2). However, going forward, as children in lower grades move into higher grades, high schools in the region will see more population losses, although less severe than the record losses in younger cohorts observed in the recent past.

Q. WHAT ARE SOME OF THE HIGHLIGHTS OF THE MAY 2018 FORECAST PREPARED BY THE MICHIGAN HOUSE FISCAL AGENCY?

A. The budget and revenue forecast also calls for a generally improving economic outlook in Michigan. Some of the key points of this forecast are:

> Michigan wage and salary employment growth was 1.2% in Calendar Year ("CY") 2017; it is forecasted to remain at 1.2% for both CY 2018 and CY 2019 before slowing to 0.9% in CY 2020.
>
> Michigan's unemployment rate was 4.6% in CY 2017; it is forecasted to decrease to 4.3% in CY 2018, 4.2% in CY 2019, and 4.1 % in CY 2020 as growth in the labor force increases more slowly than employment.
>
> Michigan personal income grew by 2.6% in CY 2017; it is forecast to increase 4.3% in CY 2018,4.4% in CY 2019, and 4.5% in CY 2020.
>
> Michigan wage and salary income increased by 2.9% in CY 2017; it is forecast to increase 4.4% in CY 2018 and 4.5% in both CY 2019 and CY 2020 as the labor market tightens.
>
> Inflation (as measured by the Detroit Consumer Price Index) is forecast to increase 2.1% in CY 2018,1.7% in CY 2019, and 2.4% in CY 2020.

Q. PLEASE DISCUSS THE NOVEMBER 2018 RSQE FORECAST.

A. Consistent with the other forecasts reviewed, the University of Michigan is moderately optimistic about the short-term economic outlook in Michigan. With respect to employment, the RSQE states:

> Michigan's pace of job creation cooled from an annualized 2.2 percent in the first quarter of 2018 to an average of 1.1 percent in the second and third quarters. We expect growth to drop off a bit further in the fourth quarter before inching up slightly in 2019. The path of quarterly growth in 2020 is complicated by the 2020 Census, but job growth settles in at an annual pace of 0.6 percent by the end of 2020. Job growth averages 0.8 percent per year over 2019–2020.

With respect to disposable personal income, a measure of spending power, the RSQE states:

> We also see the growth of real disposable income ticking up two-tenths of a percentage point from 2017 to 2018. Its growth in 2018 is boosted by the decreased burden of federal taxation resulting from the TCJA of 2017. We see real disposable income growth staying roughly flat next year, as local inflation recedes but the boost from the tax cuts fades.

Real income growth jumps by six-tenths of a percentage point in 2020, reflecting faster nominal income growth and stable inflation.

Q. WHAT IS YOUR TAKE-AWAY FROM THESE FORECASTS?

A. These results generally confirm and support the forecast of natural gas usage in the SEMCO Gas's service territory documented above. Specifically, these forecasts:

1. support the modest increases in the number of customers served that underpin the above billing determinant forecast; and

2. support usage per customer estimates that remain flat or increase only slightly throughout the 2018-2020 forecast period.

Class Cost of Service

Q. WHAT IS A CLASS COST OF SERVICE ("CCOSS") ANALYSIS?

A. A CCOSS analysis is the process by which the costs that a utility incurs to serve particular classes of customers are linked to the classes of customers that caused those costs to be incurred.

Q. WHY IS IT NECESSARY TO ALLOCATE COSTS TO THE DIFFERENT CUSTOMER CLASSES

A. It is a generally accepted utility ratemaking principle that rates should be based on costs. This statement applies not only to the overall level of costs incurred by the utility, but also to the costs that the utility incurs to serve individual services, classes of customers, and segments of the utility's business. Adherence to this principle is complicated by the fact that many of the costs incurred to provide different types of service are "joint" costs and many are "common" costs, neither of which has a theoretically precise method by which they can be assigned to the different products produced as a result of the incurrence of these costs.

Joint costs occur when the provision of one service is an automatic by-product of another (e.g., the delivery of natural gas at different times of the year). Common costs are incurred when several outputs are produced using the same facilities or inputs (e.g., administrative and general expenses).

Thus, cost of service studies are the primary method used to allocate the common and joint costs incurred by the utility in serving different customer classes. They are used for five purposes:

1. To attribute costs to different categories of customers based on how those customers cause costs to be incurred;
2. To determine how costs will be recovered from customers within each customer class;
3. To calculate the costs of individual types of service based on the costs each service requires the utility to expend;
4. To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets; and
5. To separate costs between different regulatory jurisdictions.

Q. HOW ARE THE COSTS INCURRED BY THE UTILITY ALLOCATED TO THE DIFFERENT CUSTOMER CLASSES

A. These costs are allocated to the different customer classes in three steps: functionalization, classification, and allocation.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the process whereby the capital and operating costs incurred by the utility to provide service are categorized by function. The typical functions of a natural gas utility are transmission, distribution, customer service and facilities, and administrative and general. The transmission function includes those assets and expenses associated with the delivery of natural gas from the field to the distribution system. The assets and expenses involved in the delivery of natural gas to ultimate customers, except those that can be directly assigned to a customer, are included in the distribution function. Those distribution costs that can be directly assigned to a customer (e.g., service drops and meters) plus the meter reading and other customer service functions such as billing and collections are included in the customer service and facilities function. The administrative and general function includes management costs that cannot be directly assigned to the other major cost functions.

Q. WHY DOES ONE FUNCTIONALIZE COSTS?

A. Costs are functionalized so that they can be more easily classified, which is the next step in the cost of service analysis.

Q. HOW WAS THE FUNCTIONALIZATION PROCESS PERFORMED FOR SEMCO GAS?

A. The Company's accounting processes follow the FERC Uniform System of Accounts. In large measure, this system of accounts records costs by the function for which they were incurred. Thus, the costs that I work with in the cost of service analysis are already grouped by function.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. The classification process recognizes that the utility's costs are incurred for several purposes: to meet customers' peak demands (demand-related costs), to provide energy (energy- or commodity-related costs), and because there are customers on the system (customer-related costs). The classification process groups the utility's costs by the purpose for which they were incurred. The cost of odorant is the best example of a cost that is incurred in direct proportion to the amount of natural gas that flows through the system and is therefore classified as an energy-related cost. On the other hand, metering costs are primarily driven by the number of customers on the system and would be classified as customer-related costs.

Q. HOW WERE THE COMPANY'S COSTS CLASSIFIED IN THIS STUDY?

A. In general, I followed the classifications that are generally accepted by utilities and state commissions and relied upon the suggested classification of the National Association of Regulatory Utility Commissioners (NARUC). Moreover, the classifications used in the class cost of service study are intended to be the same as those utilized by the Company in its last general rate case, U-16169. My testimony below explains the specific classification factors employed.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. The allocation process is one in which the functionalized and classified costs from above are assigned to specific customer classes. It is assumed that the load characteristics of the customers within each of the major customer classes are relatively homogeneous with respect to their usage characteristics. Thus, costs can be allocated to customer classes based on these characteristics. Those costs that have been classified as demand-related costs in the classification process above are allocated among the customer classes based on demands imposed on the system during the peak day. Commodity- or energy-related costs are allocated based on the energy that the system must supply to meet the needs of these customers. Customer-related costs are allocated to the different customer classes based on the number of customers.

Q. HOW ARE THESE COSTS ALLOCATED TO THE COMPANY'S DIFFERENT CUSTOMER CLASSES?

A. First, customers are divided into groups or classes. These classes are populated with customers having similar natural gas demand characteristics. The customers within each class can therefore be billed pursuant to a single rate schedule containing a customer charge and an energy charge since their load profiles are sufficiently similar. Next, costs are examined to determine why the utility incurred them and how customers' usage characteristics impact the utility's cost incurrence decisions. Finally, a demand characteristic is associated with each cost incurred; each customer class' contribution to that cost provides the basis for the allocation of the associated cost.

Q. WHAT ARE THESE "USAGE CHARACTERISTICS" THAT CUSTOMERS PLACE ON THE SYSTEM?

A. The customer's request for service is a cost causative demand characteristic that necessarily results in an immediate investment in a regulator, a service line and metering facilities and establishes a commitment on the part of the company to provide, among other things, answers to questions and monthly billing. Hence, the very existence of this customer-utility relationship causes the incurrence of cost. The amount of natural gas taken from the utility system, usually expressed in terms of the energy content of the natural gas itself (therms or Dth) and referred to as the customer's energy use or usage, is an important cost causative characteristic as well. Additionally, as my testimony will describe in more detail, the magnitude of costs incurred to serve a customer is also driven by the customer's potential rate of energy use, usually expressed in design day usage and referred to as the customer's demand.

Q. HOW DO SUCH DEMANDS AFFECT COST INCURRENCE?

A. Cost incurrence is strongly driven by two primary factors, the physical connection to the system and the rate at which energy is used. As described above, the physical connection to the system involves investments (a regulator, a service line and metering facilities) and establishes a commitment on the part of the Company to provide monthly billing, even if no customer usage occurs. Likewise, the rate at which energy is used serves as the link to the incurrence and magnitude of demand related utility costs.

Q. WHY HAVE YOU EMPHASIZED THE PHYSICAL CONNECTION TO THE SYSTEM AND THE RATE AT WHICH ENERGY IS USED WHEN DESCRIBING COST CAUSATIVE CUSTOMER UTILIZATION FACTORS?

A. There are two very important factors that drive a natural gas utility's cost incurrence. First, it is a capital-intensive enterprise. Second, the system must be sized so that it has the capability to deliver natural gas to customers during extremely cold conditions (the “design day”), even though this intensity of usage only occurs a few days out of the year, if at all. This combination of capital intensity and sizing to meet peak day demands dictates the prominence of the physical connection and the "rate of use" customer demand characteristic when discussing the cause of cost incurrence.

Q. WHAT IS THE SIGNIFICANCE OF THE DESIGN DAY DEMAND?

A. It is necessary first and foremost to safely and reliably meet the simultaneous loads of all customers. Furthermore, transmission plant is built to meet the highest simultaneous peak established by customers. Therefore, the class contribution to the coincident design day demand is the appropriate cost causative factor to be used in the allocation of capital cost carrying charges of facilities to customer classes.

Q. WHAT ARE THE GENERAL PRINCIPLES THAT SHOULD GUIDE AN ANALYST IN PREPARING A CLASS COST OF SERVICE STUDY?

A. Allocation of costs among customer classes establishes the basis to measure existing revenue levels from such classes against the costs incurred by the Company to serve them. It also provides a basis for establishing actual tariff prices that will equitably recover the costs associated with providing service while minimizing inter-class subsidies that may otherwise occur. In brief, using the class cost of service analysis, the analyst allocates costs to cost causers. The costs that a utility incurs to serve customers are the transmission facilities to transmit the natural gas to town border stations, distribution facilities to distribute the natural gas to homes and businesses, general facilities that provide support to the first two functional groups and the related costs of operation.

Some analysts utilize energy use in a class cost of service to distribute capital costs to classes. These analysts rationalize this allocation methodology by pointing out that these facilities serve year-round load. This methodology gives no weight to the critical point that these facilities were sized and built to meet the highest demand that occurs during the winter period for SEMCO Gas.

Energy-related costs such as odorant vary with the actual throughput and should be spread to the various classes based on test year throughput. Costs such as services, regulators, meters, operation and maintenance of these facilities, customer accounting and other similar costs can be directly linked to given customer classes and should be allocated to and collected from those classes.

Q. PLEASE EXPLAIN HOW THE CCOSS DEVELOPED FOR THIS PROCEEDING WAS CONDUCTED.

A. The analytical process used for the CCOSS is consistent with the process used by the MPSC Staff and the Company, and approved by the MPSC, in prior rate proceedings. Consistent with the discussion above, the following steps outline the process used to develop the CCOSS:

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 are 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 costs are 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. PLEASE DISCUSS THE RESULTS OF THE COMPANY'S CCOSS.

A. Exhibit A-16 (PAR-7), Schedule F-1 provides the results of the Company's forecasted CCOSS with various known and measurable changes (the fully adjusted future test year). Page 1 of the schedule shows the forecasted test year rate base, allocated to customer classes. Page 2 shows operating expenses and the resulting income and revenue deficiency by class at the overall return using the Company's proposed capital structure and equity return rate of 10.50% (this latter calculation is provided on page 5 of the schedule). Page 3 shows the calculation of the strict customer-related costs, and the remaining pages support the development of the allocation factors used to allocate the costs to the different customer classes.

Q. WHAT ARE THE SOURCES OF THE DATA USED IN THE STUDY?

A. Forecasted sales and customer data are summarized in Exhibit A-15 (PAR-4), Schedule E-1 and Exhibit A-15 (PAR-5), Schedule E-2, respectively. Forecasted revenue data are summarized in Exhibit A-16 (JLD-1), Schedule F-2. The cost data for the CCOSS were provided by the Company and are derived from the Company's annual filing and the required rate case filing exhibits. Known and measurable cost calculations are shown in those same exhibits. Therefore, the study reflects the expected cost of operations for the historical period ended December 31, 2020, 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. DOES THAT COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

PAUL H. RAAB

Mr. Raab's consulting focus is on the regulated public utility industry. His experience includes mathematical and economic analyses and system development and his areas of expertise include regulatory change management, load forecasting, supply-side and demand-side planning, management audits, mergers and acquisitions, costing and rate design, and depreciation and life analysis.

PROFESSIONAL EXPERIENCE

Mr. Raab has directed or has had a key role in numerous engagements in the areas listed above. Representative clients are provided for each of these areas in the subsections below.

Regulatory Change Management. Mr. Raab has recently been assisting both electric and natural gas utilities as they prepare to operate in an environment that is significantly different from the one they operate in today. This work has involved the development of unbundled cost of service studies; the development of strategies that will allow companies to prosper in a restructured industry; retail access program development, implementation, and evaluation; and the development of innovative ratemaking approaches to accompany changes in the regulatory structure. Representative clients for whom he has performed such work include:

- Texas Gas Service
- Virginia Natural Gas
- UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.
- The Peoples Natural Gas Company d/b/a Dominion Peoples
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania, Inc.
- Aquila
- Kansas Corporation Commission
- Atmos Energy Corporation
- Electric Cooperatives' Association
- Cleco
- Washington Gas
- Western Resources
- Kansas Gas Service
- Mid Continent Market Center.

Load Forecasting. Mr. Raab has broad experience in the review and development of forecasts of sales forecasts for electric and natural gas utilities. This work has also included the development of elasticity of demand measures that have been used for attrition adjustments and revenue requirement reconciliations. Representative clients for whom he has performed such work include:

- Washington Gas Energy Services
- Central Louisiana Electric Company
- Washington Gas
- Saskatchewan Public Utilities Review Commission
- Union Gas Limited
- Nova Scotia Power Corporation
- Cajun Electric Power Cooperative
- Cincinnati Gas & Electric
- Commonwealth Edison Company
- Cleveland Electric Illuminating
- Public Service of Indiana
- Atlantic City Electric Company
- Detroit Edison Company
- Sierra Pacific Power
- Connecticut Natural Gas Corporation
- Appalachian Power Company
- Missouri Public Service Company
- Empire District Electric Company
- Public Service Company of Oklahoma
- Wisconsin Electric Power Company
- Northern States Power Company
- Iowa State Commerce Commission
- Missouri Public Service Commission.

Supply Side Planning. Mr. Raab has assisted clients to determine the most appropriate supply-side resources to meet future demands. This assistance has included the determination of optimal sizes and types of capacity to install, determination of production costs including and excluding the resource, and an assessment of system reliability changes as a result of different resource additions. Much of this work for the following clients has been done in conjunction with litigation:

- Enstar Natural Gas
- AGL Resources
- Washington Gas
- Soyland Electric Cooperative
- Houston Lighting and Power
- City of Farmington, New Mexico
- Big Rivers Electric Cooperative
- City of Redding, California
- Brown & Root
- Kentucky Joint Committee on Electric Power Planning Coordination
- Sierra Pacific Power.

Demand Side Planning. Demand Side Planning involves the forecasting of future demands; the design, development, implementation, and evaluation of demand side management programs; the determination of future supply side costs; and the integration of cost effective demand side management programs into an Integrated Least Cost Resource Plan. Mr. Raab has performed such work for the following clients:

- UGI Utilities
- Dominion Peoples Gas
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania
- Kansas Gas Service
- Atmos Energy Corporation
- Black Hills Gas Company
- Oklahoma Natural Gas Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- Montana-Dakota Utilities.

Management Audits. Mr. Raab has been involved in a number of management audits. Consistent with his other experience, the focus of his efforts has been in the areas of load forecasting, demand- and supply-side planning, integrated resource planning, sales and marketing, and rates. Representative commission/utility clients are as follows:

- Public Utilities Commission of Ohio/East Ohio Gas
- Kentucky Public Service Commission/Louisville Gas & Electric
- New Hampshire Public Service Commission/Public Service Company of New Hampshire
- New Mexico Public Service Commission/Public Service of New Mexico
- New York Public Service Commission/New York State Electric & Gas
- Missouri Public Service Commission/Laclede Gas Company
- New Jersey Board of Public Utilities/Jersey Central Power & Light
- New Jersey Board of Public Utilities/New Jersey Natural Gas
- Pennsylvania Public Utilities Commission/ Pennsylvania Power & Light
- California Public Utilities Commission/San Diego Gas & Electric Company.

Mergers and Acquisitions. Mr. Raab has been involved in a number of merger and acquisition studies throughout his career. Many of these were conducted as confidential studies and cannot be listed. Those in which his involvement was publicly known are:

- ONEOK, Inc./Southwest Gas Corporation
- Western Resources
- Constellation.

Costing and Rate Design Analysis. Mr. Raab has prepared generic rate design studies for the National Governor's Conference, the Electricity Consumer's Resource Council, the Tennessee Valley Industrial Committee, the State Electricity Commission of

Western Australia, and the State Electricity Commission of Victoria. These generic studies addressed advantages and disadvantages of alternative costing approaches in the electric utility industry; the strengths and weaknesses of commonly encountered costing methodologies; future tariff policies to promote equity, efficiency, and fairness criteria; and the advisability of changing tariff policies. Mr. Raab has performed specific costing and rate design studies for the following companies:

- New Mexico Gas
- SEMCO Gas
- Enstar Natural Gas
- Atmos Energy Corporation
- Southern Maryland Electric Cooperative, Inc.
- Comcast Cable Communications, Inc.
- Cable Television Association of Georgia
- Devon Energy
- Aquila
- Oklahoma Natural Gas
- Semco Energy Gas Company
- Laclede Gas
- Western Resources
- Kansas Gas Service Company
- Central Louisiana Electric Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- KPL Gas Service Company
- Allegheny Power Systems
- Northern States Power
- Interstate Power Company
- Iowa-Illinois Gas & Electric Company
- Arkansas Power and Light
- Iowa Power & Light
- Iowa Public Service Company
- Southern California Edison
- Pacific Gas & Electric
- New York State Electric & Gas
- Middle South Utilities
- Missouri Public Service Company
- Empire District Electric Company
- Sierra Pacific Power
- Commonwealth Edison Company
- South Carolina Electric & Gas
- State Electricity Commission of Western Australia
- State Electricity Commission of Victoria, Australia
- Public Service Company of New Mexico

- Tennessee Valley Authority.

Depreciation and Life Analysis. Mr. Raab has extensive experience in depreciation and life analysis studies for the electric, gas, rail, and telephone industries and has taught a course on depreciation at George Washington University, Washington, DC. Representative clients in this area include:

- Champaign Telephone Company
- Plains Generation & Transmission Cooperative
- CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- Lea County Electric Cooperative, Inc.
- North Carolina Electric Membership Cooperative
- Alberta Gas Trunk Lines (NOVA)
- Federal Communications Commission.

TESTIMONY

The following table summarizes Mr. Raab's testimony experience.

Jurisdiction	Docket Number	Subject
Alaska	U-09-069, U-09-070	Rate Design
	U-14-010	Rate Design
Colorado	14AL-0300G	Costing/Rate Design
	17AL-0363G	Costing/Rate Design
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
	1053	Costing/Rate Design
	1079	Rate Design
	1093	Costing/Rate Design
	1137	Costing/Rate Design
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning

Jurisdiction	Docket Number	Subject
Iowa	RPU-05-2	Costing/Rate Design
Kansas	174,155-U	Retail Competition
	176,716-U	Costing/Rate Design
	98-KGSG-822-TAR	Rate Design
	99-KGSG-705-GIG	Restructuring
	01-KGSG-229-TAR	Rate Design
	02-KGSG-018-TAR	Rate Design
	02-WSRE-301-RTS	Cost of Service
	03-KGSG-602-RTS	Cost of Service/Rate Design
	03-AQLG-1076-TAR	Rate Design
	05-AQLG-367-RTS	Cost of Service/Rate Design
	06-KGSG-1209-RTS	Cost of Service/Rate Design
	07-AQLG-431-RTS	Rate Design
	08-WSEE-1041-RTS	Cost of Service
	10-KCPE-415-RTS	Cost of Service/Rate Design
	10-KGSG-421-TAR	Demand Side Planning
	10-KCPE-795-TAR	Demand Side Planning
	12-WSEE-112-RTS	Cost of Service/Rate Design
	12-KGSG-835-RTS	Cost of Service/Rate Design
	12-GIMX-337-GIV	Demand Side Planning
	12-KG&E-718-CON	Cost of Service
	13-KG&E-451-CON	Cost of Service
	13-WSEE-629-RTS	Cost of Service/Rate Design
	14-ATMG-320-RTS	Cost of Service/Rate Design
	15-WSEE-181-TAR	Demand Side Planning
	15-KCPE-116-RTS	Cost of Service/Rate Design
	16-ATMG-079-RTS	Cost of Service/Rate Design
	16-KGSG-491-RTS	Cost of Service/Rate Design
	16-KCPE-446-TAR	Demand Side Planning
	18-KCPE-480-RTS	Cost of Service/Rate Design
	18-KGSG-560-RTS	Cost of Service/Rate Design
Kentucky	9613	Capacity Planning
	97-083	Management Audit
	2009-00354	Cost of Service
	2013-00148	Cost of Service
	2015-00343	Cost of Service
	2017-00349	Cost of Service
	2018-00281	Cost of Service
Louisiana	U-21453	Restructuring/Market Power

Jurisdiction	Docket Number	Subject
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design
	9092	Costing/Rate Design
	9104	Costing/Rate Design
	9106	Costing/Rate Design
	9180	Capacity Planning
	9267	Costing/Rate Design
	9433	Capacity Planning
	9481	Costing
Michigan	U-6949	Load Forecasting
	U-13575	Costing/Rate Design
	U-16169	Costing/Rate Design
Missouri	GR-2002-356	Rate Design
Montana	D2005.4.48	Costing/Rate Design
Nebraska	NG-0001, NG-0002, NG-0003	Rate Design
	NG-0041	Rate Design
Nevada	81-660	Load Forecasting
New Jersey	OAL# PUC 1876-82 BPU# 822-0116	Load Forecasting
New Mexico	2087	Capacity Planning
	11-00042-UT	Rate Design
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting

Jurisdiction	Docket Number	Subject
Oklahoma	27068	Load Forecasting
	PUD 200400610	Costing/Rate Design
	PUD 200700449	Demand Side Planning
	PUD 200800348	Costing/Rate Design
	PUD 200900110	Costing/Rate Design
	PUD 201000143	Demand Side Planning
	PUD 201100170	Demand Side Planning
	PUD 201200029	Demand Side Planning
	PUD 201300007	Demand Side Planning
	PUD 201300032	Demand Side Planning
	PUD 201400069	Demand Side Planning
	PUD 201500138	Demand Side Planning
	PUD 201500213	Costing/Rate Design
	PUD 201600132	Demand Side Planning
	PUD 201700079	Demand Side Planning
	PUD 201800028	Demand Side Planning
	PUD 201900018	Demand Side Planning
	PUD 201900021	Demand Side Planning
Pennsylvania	R-0061346	Costing/Rate Design
	M-2009-2092222, M-2009-2112952, M-2009-2112956	Demand Side Planning
	M-2009-2093216	Demand Side Planning
	M-2009-2093217	Demand Side Planning
	M-2009-2093218	Demand Side Planning
	M-2010-2210316	Demand Side Planning
	R-2010-2214415	Demand Side Planning
	M-2012-2334387, M-2012-2334392, M-2012-2334398	Demand Side Planning
	M-2012-2334388	Demand Side Planning
	M-2015-2177174	Demand Side Planning
Tennessee	PURPA Hearings	Costing/Rate Design
Texas	GUD No. 9762	Costing/Rate Design
	GUD No. 10170	Costing/Rate Design
	GUD No. 10174	Costing/Rate Design
	GUD No. 10506	Demand Side Planning
	GUD No. 10526	Demand Side Planning
	GUD No. 10779	Costing/Rate Design
US Tax Court	4870	Life Analysis
	4875	Life Analysis

Jurisdiction	Docket Number	Subject
Virginia	PUE900013	Demand Side Planning
	PUE920041	Costing/Rate Design
	PUE940030	Costing/Rate Design
	PUE940031	Costing/Rate Design
	PUE950131	Capacity Planning
	PUE980813	Costing/Rate Design
	PUE-2002-00364	Costing/Rate Design
	PUE-2003-00603	Costing/Rate Design
	PUE-2006-00059	Costing/Rate Design
	PUE-2008-00060	Demand Side Planning
	PUE-2009-00064	Demand Side Planning
	PUE-2012-00118	Demand Side Planning
	PUE-2015-00132	Demand Side Planning
	PUE-2015-00138	Demand Side Planning
	PUE-2016-00001	Capacity Planning
	PUR-2018-00080	Capacity Planning
	PUR-2018-00193	Demand Side Planning
West Virginia	79-140-E-42T	Capacity Planning
	90-046-E-PC	Demand Side Planning
Wisconsin	05-EP-2	Capacity Planning

In addition, Mr. Raab has presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee and the Province of Saskatchewan. He is a member of the Advisory Board of the Expert Evidence Report, published by The Bureau of National Affairs, Inc.

EDUCATION

Mr. Raab holds a B.A. (with high distinction) in Economics from Rutgers University and an M.A. from SUNY at Binghamton with a concentration in Econometrics. While attending Rutgers, he studied as a Henry Rutgers Scholar.

PUBLICATIONS AND PRESENTATIONS

Mr. Raab has published in a number of professional journals and spoken at a number of industry conferences. His publications/ presentations include:

- "Natural Gas as an Electric DSM Tool," American Gas Association Membership Services Committee Meeting, Williamsburg, VA, September 15, 2009.

- "Electric-to-Gas Fuel Switching," NARUC Summer Meeting, Seattle, WA, July 20, 2009.

- "The Future of Fuel in Virginia: Natural Gas," The Twenty-Seventh National Regulatory Conference, Williamsburg, VA, May 19, 2009.

- "Revenue Decoupling for Natural Gas Utilities," Energy Bar Association Midwest Energy Conference, Chicago, IL, March 6, 2008.

- "Responses to Arrearage Problems from High Natural Gas Bills," American Gas Association Rate and Regulatory Issues Seminar, Phoenix, AZ, April 8, 2004.

- "Factors Influencing Cooperative Power Supply," National Rural Utilities Cooperative Finance Corporation Independent Borrower's Conference, Boston, MA, July 3, 1997.

- "Current Status of LDC Unbundling," American Gas Association Unbundling Conference: Regulatory and Competitive Issues, Arlington, VA, June 19, 1997.

- "Balancing, Capacity Assignment, and Stranded Costs," American Gas Association Rate and Strategic Planning Committee Spring Meeting, Phoenix, AZ, March 26, 1997.

- "Gas Industry Restructuring and Changes: The Relationship of Economics and Marketing" (with Jed Smith), National Association of Business Economists, 38th Annual Meeting, Boston, MA September 10, 1996.

- "Improving Corporate Performance By Better Forecasting," 1996 Peak Day Demand and Supply Planning Seminar, San Francisco, CA, April 11, 1996.

- "Natural Gas Price Elasticity Estimation," AGA Forecasting Review, Vol. 6, No. 1, November 1995.

- "Assessing Price Competitiveness," Competitive Analysis & Benchmarking for Power Companies, Washington, DC, November 13, 1995.

- "Avoided Cost Concepts and Management Considerations," Workshop on Avoided Costs in a Post 636 Gas Industry: Is It Time to Unbundle Avoided Cost? Sponsored by the Gas Research Institute and Wisconsin Center for

Demand-Side Research, Milwaukee, WI, June 29, 1994.

- "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.

- "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.

- "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.

- "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.

- "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.

- "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.

- "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.

- "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.

- "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.

- "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February, 1982.

- "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May, 1981.

- "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, March 20, l980.

- "The Ernst & Whinney Forecasting Model," Forecasting Energy & Demand

Requirements, University of Wisconsin - Extension, October 8, l979.

- "Marginal Cost in Electric Utilities - A Multi-Technology Multi-Period Analysis" (with Frederick McCoy), ORSA/Tims Joint National Meeting, Los Angeles, California, November 13-15, 1978.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of SEMCO ENERGY GAS COMPANY for authority to increase its rates for the distribution and transportation of natural gas and for other relief.	)))))	Case No. U-20479

DIRECT TESTIMONY AND EXHIBITS

OF JENNIFER L. DENNIS

ON BEHALF OF SEMCO ENERGY GAS COMPANY

May 31, 2019

Direct Testimony of Jennifer L. Dennis
On Behalf of
SEMCO ENERGY Gas Company

Q. Please state your name and business address.

A. Jennifer L. Dennis, 1411 Third Street, Suite A, Port Huron Michigan 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 the Rates and Regulatory Manager.

Q. Please describe your educational background and business experience.

A. I graduated from Grand Valley State University in 2002 with a Bachelor of Science degree. In 2010, I graduated from Central Michigan University with a Master of Public Administration degree. Between February 2003 and August 2015, I worked for the St. Clair County Friend of the Court, holding various positions of increasing responsibility. In August 2015, I was hired by SEMCO Gas as the Customer Energy Management Coordinator, managing the implementation of the Company's Energy Optimization, now the Energy Waste Reduction ("EWR"), and residential appliance warrantee programs. In July 2016, I became the Gas Supply Resource Planner for which I continued all responsibilities regarding the EWR program as well as providing additional support in planning and forecasting for the Gas Supply Department. In December 2017, I was promoted to Rates and Regulatory Manager.

Q. What are your responsibilities as Rates and Regulatory Manager?

A. Under the supervision of the Director of Regulatory Affairs, my responsibilities include oversight of the Company's regulatory filings and EWR program implementation, management of contractual relationships in EWR and other regulatory areas, and the overall compliance with rates and regulatory orders.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC")?

A. Yes. I provided previous testimony and exhibits in the following cases:

U-18016 – 2015 EWR Reconciliation

U-18179 – 2017 EWR Amended Plan

U-18270 – 2018/2019 EWR Biennial Plan

U-18340 – 2016 EWR Reconciliation

U-20037 – 2017 EWR Reconciliation

U-18157 – 2017/2018 Gas Cost Recovery ("GCR") Plan

U-18417 – 2018/2019 GCR Plan.

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

A. The purpose of my testimony is as follows:

1) Describe the methodology behind the Company's proposed rate design;

2) Explain any necessary adjustments to the Cost of Service Study and the impact these adjustments have on rates;

3) Demonstrate examples of typical customer bills in each of the sales rate classes;

4) Present the Company's proposed alternative to a Revenue Decoupling Mechanism ("RDM") in response to the Company's EWR program, and;

5) Identify all major changes to the Company's Rate Book.

Q. What exhibits are you sponsoring in this case?

A. I am sponsoring the following exhibits:

- Exhibit A-16 (JLD-1), Schedule F-2: Summary of Present and Proposed Revenue by Rate Schedule;
- Exhibit A-16 (JLD-2), Schedule F-2.1: Summary of Present and Proposed Rates by Rate Schedule;
- Exhibit A-16 (JLD-3), Schedule F-2.2: Calculation of Rate Design Targets;
- Exhibit A-16 (JLD-4), Schedule F-3: Present and Proposed Revenue Detail;
- Exhibit A-16 (JLD-5), Schedule F-3.1: Alternative Revenue Decoupling Mechanism;
- Exhibit A-16 (JLD-6), Schedule F-4: Comparison of Present and Proposed Monthly Bills; and
- Exhibit A-16 (JLD-7), Schedule F-5: Proposed Tariff Sheets.

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

A. Yes.

<u>SUMMARY OF PROPOSED RATE DESIGN</u>

Q. Please describe Exhibit A-16 (JLD-1), Schedule F-2.

A. Exhibit A-16 (JLD-1), Schedule F-2, Summary of Present and Proposed Revenue by Rate Schedule, provides a review of rate changes for each rate schedule from current rates to proposed rates, based on test year forecasted customer counts and sales volumes. Page 1 of 2 provides the percent change to total revenue, including the cost of gas, representative of the percent increase customers will experience. Page 2 of 2 provides the percent change to delivery revenue only, excluding the cost of gas.

Q. What is the Company's total present revenue, excluding the cost of gas?

A. As calculated in Exhibit A-16 (JLD-1), Schedule F-2, page 2 of 2, the total present revenue excluding cost of gas revenue is $128,953,129.

Q. Please describe the Company's approach to rate design in this case.

A. The Company has designed its proposed rates to generate the revenue recovery necessary from each customer class as reflected in the test year Cost of Service Study ("COSS"), developed by Witness, Paul Raab. As described below, adjustments to the COSS in the rate design were made to minimize significant increases to any one customer rate class. The proposed rate design maintains the existing rate structure for the residential and general service customer classes. The Company proposes moving the transportation customer class from an on-peak/off-peak structure to a flat rate.

<u>Residential</u>

After applying all adjustments, the proposed increase to the Residential Class inclusive of the cost of gas commodity is 14%, as shown on Exhibit A-16 (JLD-1), Schedule F-2, page 1 of 2. When excluding the cost of gas, as shown on page 2 of 2, the change reflects a 30% increase.

<u>General Service ("GS")</u>

After applying all adjustments, the proposed increase to the General Service Class inclusive of the cost of gas commodity is 9%, as shown on Exhibit A-16 (JLD-1), Schedule F-2, page 1 of 2. When excluding the cost of gas, as shown on page 2 of 2, the change reflects a 27% increase. The break-even points remain the same at 660 Dekatherms ("Dth") for GS-1 to GS-2 and changed by only one Dth to 2851 Dth for GS-2 to GS-3.

<u>Transportation ("TR")</u>

Transortation customers' cost of gas is unknown. As shown on page 2 of 2, the change in transportation rates only reflects a 32% increase. The break-even points remain within a few Dth at 50,103 Dth for TR-1 to TR-2 and 300,177 Dth for TR-2 to TR-3.

Q. Please explain why the Company proposes moving the transportation customer class from an on-peak/off-peak variable rate to a flat rate.

A. The primary purpose of the proposed change is for simplicity. The flat rate will eliminate a layer of complexity for both the customer and the Company. The flat rate structure brings SEMCO Gas in-line with most other rate-regulated gas utilities.

Q. Please describe the treatment of the Main Replacement Program ("MRP") surcharges on the present and proposed revenue for each rate schedule.

A. The present and proposed MRP revenues for each rate schedule are developed in Exhibit A-16 (JLD-4), Schedule F-3, Present and Proposed Revenue Detail. As described by Company Witness Steven McLean the current MRP charges will end when new rates are established in this proceeding, therefore proposed MRP rates are left at zero. The proposed MRP surcharges for the 2021-2025 period are supported by Witness McLean as reflected in Exhibit A-48 (SQM-4).

ALLOCATION OF THE PROPOSED REVENUE DEFICIENCY

Q. What ratemaking adjustments were made to the COSS?

A. In addition to the rate stability adjustments described below, the Company has made adjustments to the COSS to account for the proposed low-income credit programs and discounted rates offered through special contracts.

Low-Income Credit Programs

As described in detail by Company witness, Laurie Owens, and as permitted by Public Act 341 of 2016 ("PA 341"), the Company proposes a new low-income credit program which allows for a bill credit to assist customers with household incomes at or below 150% the federal poverty guidelines. A Low Income Assistance Credit ("LIAC") program is proposed, allowing 3,200 qualifying customers a monthly credit of $30.00. The program's total cost of $1,152,000 is then deferred across all customer classes in accordance with the PA 341. Page 2 of Exhibit A-16 (JLD-3) Schedule F-2.2, Calculation of Rate Design Targets, shows the allocation of the low-income program costs based on the percent of the total revenue requirement for that customer class. The COSS is then adjusted on page 1 of the same exhibit to reflect these program costs.

Special Contracts

For reasons addressed in Witness Steven McLean's testimony, special rates have been necessitated for 5 transport customers. Since it has been shown that all customer classes benefit from the interconnection of these customers to the distribution system, it is prudent that the difference between negotiated rates and tariff rates for these customers be allocated across all customer classes. In Exhibit A-16 (JLD-3) Schedule F-2.2, Calculation of Rate Design Targets, the allocation of the shortfall from these contracts is calculated in column (e) of page 2 then adjusted against the COSS on page 1, line 3.

Q. Please describe the rate stability adjustments of Exhibit A-16 (JLD-3), Schedule F-2.2.

A. The COSS proposes increases across all rate classes to varying degrees in order to achieve the overall revenue requirement. It is the Company's position that gradualism should be exercised to mitigate significant increases to any one rate class. Lines 13-14 of this exhibit calculate a redistribution of rates to more evenly spread the revenue deficiency thereby preventing extreme rate increases to a few rate classes.

Q. What is the percent increase to each customer class over the test year present revenue after applying each of these adjustments?

A. As shown on page 1, line 13 of Exhibit A-16 (JLD-3) Schedule F-2.2, Calculation of Rate Design Targets, the percent increase by class is as follows: Residential = 30%, GS-1 = 30%, GS-2 = 25%, GS-3 = 25%, TR-1 = 24%, TR-2 = 40%, TR-3 = 55%. The proposed rate changes by customer class and by fee type are outlined on Exhibit A-16 (JLD-2), Schedule F-2.1, Summary of Present and Proposed Rates by Rate Schedule.

<u>TYPICAL BILLS</u>

Q. Please describe Exhibit A-16 (JLD-6), Schedule F-4.

A. Exhibit A-16 (JLD-6), Schedule F-4, Comparison of Present and Proposed Monthly Bills, provides an example of monthly billing at different usage intervals for each sales rate class. The Residential Class does not include any adjustments for LIAC.

<u>ALTERNATIVE REVENUE DECOUPLING MECHANISM</u>

Q. Please describe the purpose of a RDM.

A. As permitted in Public Act 295 of 2008 and upheld in the Amendatory Public Act 342 of 2016 (collectively "Energy Legislation") SEMCO Gas is proposing an alternative to the traditional revenue decoupling true-up mechanism described in Section 85(5) of the Energy Legislation. The proposed alternative is intended to add stability to the Company's revenue in response to decreasing revenues caused by the successful effects of the Company's EWR program. Unlike the traditional RDM, the Company's alternative RDM is not intended to recover lost revenue resulting from the reduced consumption caused by the EWR program, and as such offers no true-up mechanism.

Q. Please describe methodology behind the Company's proposed alternative RDM.

A. The traditional RDM allows for the Company to recoup a portion of any revenue under-recovery for Residential and General Service customer classes, with the exception of the largest General Service customer class, that may be attributable to the EWR program. The first year recovery is capped at 1.125% of the distribution revenue determined in the most recent rate case. The cap increases to 2.25% the second year of the RDM. The intention is to provide a degree of revenue stability for gas utilities participating in EWR. Alternatively, SEMCO is proposing instead to shift 1.125% of volumetric distribution revenue for eligible customers to the fixed monthly customer charge. As shown on Exhibit A-16 (JLD-5), Schedule F-3.1, this alternative methodology begins with calculating the RDM qualifying revenues and capping them at 1.125%. The capped RDM revenue is then divided by the Test Year customer count and rounded to the nearest tenth to determine the per meter adjustment to the COSS Customer Charge.

Q. What are the resulting changes to the customer charge for each affected customer class as calculated by the alternative RDM?

A. As shown in Exhibit A-16 (JLD-5), Schedule F-3.1, the Residential customer charge increases by $2.40 to $17.40 while the customer charge for GS-1 customers increases $6.10 to $21.10 and the GS-2 customer charge increases $27.10 to $70.90.

Q. Does the Company proposed to charge the customer charges for Residential, GS-1 and GS-2 customers as calculated by the alternative RDM?

A. Not entirely. SEMCO Gas proposes a customer charge for residential customers equal to that calculated in Exhibit A-16 (JLD-5), Schedule F-3.1. However, because SEMCO Gas is recommending to maintain the current break-even points for GS customers, it did not make sense to use the customer charges as calculated in the alternative RDM for either the GS-1 or GS-2 customer classes. Instead, SEMCO Gas is proposing to maintain the current approach of setting the GS-1 customer charge equal to that of the Residential class and adjusting the GS-2 customer charge appropriately to achieve the current break even point of 660 Dth. The result reduces some of the revenue stability gained by the altenative RDM calculation but, based on customer counts in each of the affected classes, the loss is minimal.

Q. What final customer charges are the Company proposing for Residential, GS-1 and GS-2 customers?

A. Residential - $17.40

GS-1 - $17.40

GS-2 - $36.20

Q. Please explain why the Company is not recommending a true-up mechanism.

A. The alternative approach proposed by the Company shifts a small percentage of revenue collection from a volumetric charge, directly influenced by the EWR program's effort to reduce consumption, to a fixed charge, unaffected by the outcomes of the EWR program. The method itself provides symmetrical revenue stability, equally reducing the opportunity for the Company to under or over earn.

<u>RATE BOOK CHANGES</u>

Q. Please explain Exhibit A-16 (JLD-7), Schedule F-5.

A. Exhibit A-16 (JLD-7), Schedule F-5 shows the changes proposed for the Company's Rate Book for Natural Gas Services. Pages 1-2 is a summary table outlining the proposed changes for each section and sheet of the Company's tariff. The sheet numbers listed correspond to the sheet numbers of the current Rate Book. Pages 3-96 of the same exhibit are the Rate Book pages with redline changes, while pages 97-176 are the clean copies.

Q. Please review the major changes proposed for the Company's Rate Book.

A. <u>Section A</u>

Supplemental service charges for all customers has been updated with a new flat fee for remote monitoring equipment installed at the customer's request. The service and fee is not new, however it had previously been based on time and materials costs per job. It will now be a flat fee.

<u>Section C</u>

Minimum Use language has been added to ensure system investments on behalf of a single customer are to the benefit of all ratepayers. Additionally, the Discontinuance of Services section has been revised to include discontinued service for customers who have tampered with or modified the Company's meter or other system facilities without the consent and supervision of the Company and recoupment of any expenses associated with gas theft. Sponsored by Witness Steve McLean and as described in his testimony, the Customer Attachment Program carrying cost and discount rate have been updated and a new Main Replacement Program has been added.

<u>Section D</u>

Also sponsored by Witness McLean in Section D, Credits A and B have been removed and replaced with the new Infrastructure Reliability Improvement Plan ("IRIP"). Witness Laurie Owens sponsors the addition of a Low Income Assistance Credit as discussed in more detail in her testimony while the rate allocation has been discussed previously here. New Residental and General Service rates as discussed previously in this testimony are also updated on their respective rate sheets.

Section E

Transportation rate sheets have also been updated to reflect the rate design previously discussed. Witness McLean also sponsors the replacement of Credit A and B rate sheets with the addition of IRIP. All other changes in Section E are sponsored by Witness Walt Fitzgerald and described in detail in his testimony, including the addition of the Facility Improvement Demand Surcharge and the Off-System Transportation Services section.

Section F

All changes to Section F are sponsored by Witness Fizgerald and described in his direct testimony.

Q. Does this conclude your testimony at this time?

A. Yes.