Direct Testimony and Schedules
Joylyn C. Hoffman Malueg

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

Docket No. G011/GR-13-617

Exhibit _____

Class Cost of Service Study

September 30, 2013

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joylyn C. Hoffman Malueg. My business address is Integrys Energy Group, Inc. ("Integrys"), 700 North Adams Street, P.O. Box 19001, Green Bay, WI 54307-9001.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Rate Case Consultant in the Regulatory Affairs Department of Integrys Business Support, LLC ("IBS"). Both Minnesota Energy Resources Corporation ("MERC") and IBS are wholly-owned subsidiaries of Integrys.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I am a 1999 graduate of the University of Wisconsin – Green Bay where I received a Bachelor of Science Degree in Mathematics with a Statistical emphasis. I received my Master of Business Administration degree from Cardinal Stritch University, Milwaukee, Wisconsin, in February 2006. I am also a Certified Management Accountant ("CMA"), having received such certification in November 2009 from the Institute of Certified Management Accountants. From 1999 to 2001, I worked for two separate companies performing retirement benefits analysis and valuation. In March 2001, I was hired by Wisconsin Public Service Corporation ("WPSC") as a Revenue Requirements Forecaster in the Rates and Economic Evaluation Department. While working as a Revenue Requirements Forecaster, I was primarily responsible for revenue requirements and cost of service analyses pertaining to WPSC's wholesale jurisdiction. In October 2003, my job title changed to Rate Analyst within the Regulatory Affairs Department. My primary job responsibilities during that time related to revenue requirements analyses for WPSC's Michigan retail jurisdiction, as well as performing revenue requirement analyses and cost of service studies for WPSC's sister company, Upper Peninsula Power Company ("UPPCO"). In December 2006, I became a Rate Case Consultant within the Regulatory Affairs Department. Currently, my primary job duties as a Rate Case Consultant for Integrys consist of performing cost of service study analyses for all regulated Integrys subsidiaries. I am also responsible for conducting the revenue requirement analyses for WPSC's Michigan retail electric and gas jurisdictions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCY?

A. Yes, I have. I have provided sworn testimony before the Minnesota Public Utilities Commission ("Commission") in Docket Nos. G007,011/GR-08-835 and G007,011/GR-10-977, and before the Illinois Commerce Commission ("ICC") in Docket Nos. 09-0166, 09-0167, 11-0280, 11-0281, 12-0511 and 12-0512. I have also filed testimony before the Michigan Public Service Commission ("MPSC") in Case Nos. U-14410, U-14745, U-15352, U-15549, U-15988, U-15590, U-16166, U-17273 and U-17274, as well as before the Public Service Commission of Wisconsin ("PSCW") in Docket Nos. 6690-UR-119, 6690-UR-120, 6690-UR-121 and 6690-UR-122. In addition, I have participated in the preparation of various accounting and filing exhibits for WPSC, UPPCO and Michigan Gas Utilities for presentation to the MPSC, the PSCW, and the Federal Energy Regulatory Commission.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony for MERC, which is a wholly-owned subsidiary of Integrys.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My Direct Testimony and schedules describe and present MERC's cost of service study for the 2014 proposed test year.

Q. ARE YOU SPONSORING ANY INFORMATIONAL REQUIREMENTS OR SCHEDULES WITH THIS TESTIMONY?

A. Yes, I am. As required by Minn. R. 7825.4300(C), I am sponsoring Informational Requirement Document 12, Schedules 1 through 9, which contains the cost of service study for the 2014 proposed test year along with supporting data.

Q. DOES YOUR TESTIMONY ADDRESS ANY OTHER FILING REQUIREMENTS?

A. Yes, it addresses the Minnesota Public Utilities Commission's ("Commission") June 29, 2009 Findings of Fact, Conclusions of Law, and Order in Docket No. G-007,011/GR-08-835. The Order required that in future class cost of service studies filed in general rate cases, MERC include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered. Volume 3, Informational Requirement Document 12, Schedule 7, includes this explanatory filing.

In the Commission's July 13, 2012 Findings of Fact, Conclusions of Law, and Order in Docket No. G-007,011/GR-10-977 the Commission adopted the Administrative Law

Judge's ("ALJ") Proposed Order with changes. One item adopted by the Commission required MERC to allocate income taxes on the basis of taxable income by class that fully and only reflects the class cost of service study. Included in Volume 3, Informational Requirement Document 12, Schedule 1, is the class cost of service study for MERC that allocates income taxes on the basis of rate base, which, mathematically, is the same method as described above. Volume 3, Informational Requirement Document 12, Schedule 9, provides the demonstration that the rate base allocation method is mathematically equivalent to allocating income taxes on the basis of taxable income by class that fully and only reflects the class cost of service.

II. GENERAL INFORMATION

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY?

A. The purpose of a Class Cost of Service Study ("CCOSS") is to identify the revenues, costs and profitability for each class of service, as required by Minn. R. 7825.4300(C). The CCOSS analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes.

Q. HOW IS A CCOSS PREPARED?

A. The CCOSS for MERC is a fully allocated, embedded cost of service study. In general, preparing a CCOSS involves three major steps: (1) cost functionalization; (2) cost classification, and (3) cost allocation of all the costs of the utility's system to the customer classes.

The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. MERC's functional cost categories associated with gas service include: Production, Transmission, Distribution, and Customer.

Step two, cost classification, further separates the functionalized plant and expenses into the cost defining characteristics of: (1) Commodity related, which for MERC can be further broken down into categories of Purchased Gas Cost and Gas Supply Acquisition, (2) Demand, which can be further broken down into the categories of capacity related and Daily Firm Capacity related; and (3) Customer related, which for MERC can be further broken down into the categories of Customer Costs, Enhanced Services, and costs that can be Direct Assigned.

The final step of preparing a CCOSS is allocation of each functionalized and classified cost element to the customer classes.

Q. ARE THERE ANY DIFFERENCES IN THE CCOSS PRESENTED IN THIS PROCEEDING AND THE CCOSS THE COMMISSION USED AS THE BASIS FOR SETTING RATES IN MERC'S LAST GENERAL RATE CASE IN DOCKET NO. G007,011/GR-10-977?

A. Yes, there are. MERC has made the following changes to the CCOSS in the current proceeding:

1) Investment and costs functionalized to Transmission are classified 100% to demand. Previously, MERC had utilized a Minimum Size Study to classify a portion of Transmission Mains to Customer and Demand. The current methodology of classifying Transmission investment and costs to demand only is consistent with the recommendations provided by the American Gas Association ("AGA") in their Fourth Edition of Gas Rate Fundamentals (1987).

2) Based upon the Final Order in MERC's last general rate case in Docket No. G007,011/GR-10-977, it no longer has rate classes that distinguish between Town Plant and Main Line customers. The only exception to this would be the Super Large Volume – NNG rate class, which consists entirely of customers who are either directly connected to the Interstate Pipeline, or are extremely close to the Interstate Pipeline that there are a minimal amount of assets utilized by MERC to provide service to these customers. Given that Town Plant and Main Line customers are no longer distinguished in separate rate classes, the following changes were made:

    a. The allocation factor of Acct 378 Main Line was removed from the COSS in the current proceeding. This allocation method previously allocated costs that were directly attributable to Main Line customers amongst the Main Line rate classes. Due to MERC no longer distinguishing between Town Plant and Main Line rate classes, this allocation method is no longer needed. The costs within Account 378: Measuring & Regulation Equipment - General that are associated with servicing Super Large Volume – NNG customers continue to be direct assigned to those rate classes in the CCOSS.

b. The allocation factor of TP Peak Demand was removed from the CCOSS in the current proceeding. This allocation method previously allocated investment and costs in Account 379: Measuring & Regulating Equipment – Gate Station and any investment in Other Rate Base Items, such as Working Capital and Regulatory Assets & Liabilities that were Transmission related, solely to Town Plant rate classes. Due to MERC's rate classes no longer distinguishing between Town Plant and Main Line, this allocation method is no longer needed. The Weighted Peak Demand allocation factor allocates these costs in the COSS in the current general rate case.

3) Amortization relating to CIP Expense in Account 407 is direct assigned to the rate classes. Previously, MERC had utilized the Customer allocation factor, which was based upon annual customer counts for each rate class. Direct assignment of values to the appropriate rate classes should be conducted whenever possible, as recommended by both the AGA in their Fourth Edition of Gas Rate Fundamentals (1987), page 140 as well as the National Association of Regulatory Commissioners ("NARUC") in their Gas Distribution Rate Design Manual (1989), page 31.

4) Further refinement has been conducted on the allocation of Account 904: Uncollectibles Expense. Account 904 costs are split into two categories: 1) Account 904 attributable to the residential rate classes, and 2) Account 904 attributable to the commercial and industrial ("C&I") rate classes. This split was defined by the historical average of Net Write-Offs (i.e. the summation of Recoveries and Write-Offs) for these two customer groups for the calendar year ending December 31, 2012. Based on this split, 87.25% of the costs in Account 904 are attributable to residential customer classes, and the remaining 12.75% are attributable to the C&I customer classes. Once these splits are calculated, the two pieces are then allocated to the appropriate rate classes using the Direct – Residential and Direct – C&I allocation methods, which are based upon the respective customer counts of those rate classes.

Q. ARE ANY OF THESE CHANGES SUBSTANTIVE?

A. Yes. The CIP Expense being direct assigned, rather than allocated, within the CCOSS presents the most substantive change out of those listed above. The direct assignment of CIP Expense, along with the other changes made, provide for a more accurate, cost-based CCOSS. While the remainder of changes described above may seem substantive in theory, in application, MERC does not believe that these remaining changes within the CCOSS are material.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In sections III to VII, I explain the factors I used to allocate distribution, transmission, production, customer, and administrative and general costs to the rate schedules. In section VIII, I describe three unique allocators used to distribute remaining costs in the CCOSS. Section IX provides a roadmap to the schedules that present the CCOSS.

Q. WOULD YOU PLEASE EXPLAIN THE PROCEDURES USED TO DEVELOP THE COST OF SERVICE STUDIES SHOWN IN INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. There is one CCOSS submitted for the 2014 proposed test year in the instant general rate case proceeding for the Minnesota service territory. All values in the CCOSS are allocated to each rate schedule as described in the far right-hand column of each page titled “Source or Allocation Factor”. Direct assignment of values to the appropriate rate schedules was conducted whenever possible, as recommended by both the AGA in their Fourth Edition of Gas Rate Fundamentals (1987), page 140 as well as the NARUC in their Gas Distribution Rate Design Manual (1989), page 31.

Q. PLEASE DESCRIBE HOW YOU DEFINED THE CUSTOMER CLASSES IN YOUR COST OF SERVICE STUDIES.

A. In the CCOSS provided for MERC, the customer classes that were utilized follow the rate schedules under which MERC currently provides service in their Minnesota service territory. The classes shown in the CCOSS consist of the following:

1. General Service – NNG, which includes the rate schedules GS-NNG Residential, GS-NNG Small C&I, and GS-NNG Large C&I served by Northern Natural Gas;

2. General Service - Consolidated, which includes the rate schedules GS-Consolidated Residential, GS-Consolidated Small C&I, and GS-Consolidated Large C&I served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

3. Small Volume Interruptible ("SVI") Service, which includes the rate schedules SVI-NNG served by Northern Natural Gas, and SVI-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

4. Large Volume Interruptible ("LVI") Service, which includes the rate schedules LVI-NNG served by Northern Natural Gas, and LVI-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

5. Small Volume Joint Firm/Interruptible ("SVJ") Service, which includes the rate schedules SVJ-NNG served by Northern Natural Gas, and SVJ-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

6. Transportation – Small Volume Interruptible Service, which includes the rate schedules Transport - SVI-NNG served by Northern Natural Gas, and Transport - SVI-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

7. Transportation – Small Volume Joint Firm/Interruptible Service, which includes the rate schedules Transport – SVJ-NNG served by Northern Natural Gas, and Transport – SVJ-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

8. Transportation – Large Volume Interruptible Service, which includes the rate schedules Transport - LVI-NNG served by Northern Natural Gas, and Transport - LVI-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

9. Transportation – Large Volume Joint Firm/Interruptible Service, which includes the rate schedules Transport - LVJ-NNG served by Northern Natural Gas, and Transport – LVJ-Consolidated served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra;

10. Transportation – Super Large Volume Service, which includes the rate schedules Transport – Super Large Volume Joint Firm/Interruptible ("SLVJ") Service, served by Northern Natural Gas, Transport – Super Large Volume Interruptible ("SVLI") Service, served by Northern Natural Gas, and Transport – SVLI Service, served by Viking Gas Transmission, Great Lakes Gas Transmission, or Centra; and

11. Transportation for Resale.

Q. PLEASE DESCRIBE MERC'S APPROACH IN THE DEVELOPMENT OF ITS COST OF SERVICE STUDY.

A. MERC's CCOSS attempts to associate costs with customers based on cost causation. In following the direction of the AGA in their Fourth Edition of Gas Rate Fundamentals (1987), pages 136 and 137, there are some cases where there can be a direct association of costs to customers based on causation. For example, some plant costs such as investment in meters and services can be directly associated with customers. In other cases, causation can be based on a direct relationship between costs and some parameter that can be related to customers. An example of this is gas supply acquisition costs, which has a direct relationship to customers' sales. Therefore, gas supply acquisition costs are allocated to customers based on sales. Other costs may have relationships to customer parameters that are not direct, but are significantly influenced by those parameters. As stated by the NARUC in their Cost Allocation Manual (1973), page 54, distribution system costs fall into this category.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CCOSS.

A. The results with respect to revenue deficiency by customer class based on the requested revenue requirement are summarized below.

MERC – MN Service Territory	Revenue Deficiency/(Surplus) $	%
GS Residential NNG Sales	16,859,011	12.49%
GS SC&I NNG Sales	577,088	7.29%
GS LC&I NNG Sales	(4,800,473)	(8.60%)
GS Residential Consolidated Sales	3,093,240	15.46%
GS SC&I Consolidated Sales	175,939	8.29%
GS LC&I Consolidated Sales	(1,494,370)	(10.25%)
SVI NNG Sales	(891,103)	(11.12%)
SVI Consolidated Sales	(266,044)	(11.60%)
LVI NNG Sales	44,755	1.45%
LVI Consolidated Sales	66,706	3.04%
SVJ NNG Sales	(9,614)	(10.44%)
SVJ Consolidated Sales	(13,005)	(8.68%)
SVI NNG Transport	(131,342)	(54.99%)
SVI Consolidated Transport	(143,830)	(50.12%)
SVJ NNG Transport	(62,087)	(35.21%)
SVJ Consolidated Transport	(34,972)	(37.18%)
LVI NNG Transport	125,246	7.55%
LVI Consolidated Transport	64,090	15.82%
LVJ NNG Transport	98,049	16.75%
LVJ Consolidated Transport	31,089	15.76%
SLVJ NNG Transport	774,961	180.65%
SLVI NNG Transport	(681,014)	(80.06%)
SLVI Consolidated Transport	334,255	93.77%
LVI NNG FLEX Transport	246,892	98.67%
LVJ NNG FLEX Transport	223,082	66.41%
Transport for Resale	1,045	6.83%

Q. HOW SHOULD THE COMMISSION REFLECT THE RESULTS OF MERC'S CCOSS IN RATE DESIGN?

A. Mr. Greg J. Walters presents MERC's requested rate design, based in part upon the results of the CCOSS, and on other principles of rate design discussed in his testimony.

III. ALLOCATION OF DISTRIBUTION COSTS

Q. HOW DOES MERC ALLOCATE DISTRIBUTION COSTS TO CUSTOMERS IN THE CCOSS?

A. In the case of distribution costs, MERC has identified two significant cost causation relationships. Some distribution costs are incurred in order for customers to simply be connected to the distribution system. Other distribution costs are incurred due to the level of the demand of the customers.

Some gas distribution demand related costs are influenced by the sizing of facilities based on the coincident consumption of gas on the distribution facilities. These costs are allocated based upon a form of the weighted group peak demand. An example of these costs would be Accounts 378 and 379, measuring and regulating station equipment.

Other demand related costs of gas distribution facilities, such as the demand related portion of Account 376, gas mains, are influenced by both the customer maximum demand and the coincident group demand. In the CCOSS, these costs were allocated to rate schedules based upon a form of the weighted group peak demand, a daily firm capacity allocation, as well as a customer count basis.

MERC has performed a minimum-intercept distribution system study that identifies a hypothetical no-load situation with respect to the distribution gas mains used to connect customers to the system regardless of their gas usage or demand. The costs needed to support the minimum-intercept distribution system have a relationship to the number of customers, and are allocated on that basis. The costs in excess of the minimum-intercept system are related to the demand of customers, and are therefore allocated based on the customers' demands in the form of a weighted peak demand allocator and a daily firm capacity allocator.

Specifically, distribution costs are allocated within the CCOSS based upon the following methods:

1. Accounts 301, 302 & 303 Intangible Plant, 374 Land and Land Rights, and 375 Structures and Improvements were allocated to all rate schedules based on the Distribution Plant allocator.

2. Account 376 Gas Distribution Mains utilized a zero-intercept method based on a regression of cost per foot versus pipe diameter squared for the Minnesota service territory. This analysis is shown in Informational Requirement Document 12, Schedule 5.

   The regression analysis provides a split of system distribution gas mains costs that are attributable to fixed costs and demand related costs. The regression analysis shows 68.26% of the costs are attributable to the hypothetical no-load system; the remaining 31.74% are attributable to customer demand.

   The hypothetical no-load minimum system piece was allocated to each of the rate schedules based upon customer counts for customers connected to the system (counts for customers that are directly connected, or extremely close, to the Interstate Pipeline were excluded). The customer demand piece was broken down one step further into the two sub-components of customer demand and daily firm capacity ("DFC"). The customer demand piece of the analyses was allocated to rate schedules based upon firm peak demand, and the daily firm capacity piece of the customer demand was allocated to rate schedules based upon a DFC allocator.

3. Account 378 Measuring & Regulation Equipment – General was allocated based on the Account 378 demand allocator, which is a variation of the weighted peak demand allocator, and allocates costs to only the General Service and Small Volume rate schedules.

4. Account 379 Measuring & Regulation Equipment – Gate Station was allocated based on the weighted peak demand allocator.

5. Account 380 Services was allocated on a customer basis, using a weighting factor of Average Cost Per Foot for Services which was derived from estimated plant investment as of the three calendar years ending December 31, 2012 categorized by associated meter size.

6. Account 381 Meters and Account 382 Meter Connections & Installations were allocated on a meter count basis, using a weighting factor of Cost Per Meter which was based on actual plant investment as of July 31, 2013 by rate schedule, adjusted to current cost using the Handy Whitman Index.

7. Account 383 House Regulators was allocated on a customer basis to only the General Service and Small Volume rate schedules.

8. Account 385 Industrial Metering & Regulating Station Equipment was allocated based on the weighted peak demand of industrial sized customers only, excluding customers that are directly connected to the Interstate Pipeline.

IV. ALLOCATION OF TRANSMISSION COSTS

Q. HOW DOES MERC ALLOCATE TRANSMISSION COSTS TO EACH RATE SCHEDULE IN THE CCOSS?

A. Transmission costs are classified into the two sub-components of customer demand and daily firm capacity. The customer demand piece was allocated to rate schedules based upon firm peak demand, and the daily firm capacity piece of the customer demand was allocated to rate schedules based upon a DFC allocator.

Q. IN MERC'S LAST RATE CASE IN DOCKET NO. G007,011/GR-10-977, DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES WITNESS MR. ADAM HEINEN NOTED CONCERNS REGARDING THE RELIABILITY OF THE REGRESSION ANALYSES FOR DISTRIBUTION AND TRANSMISSION MAINS. HAVE YOU ADDRESSED MR. HEINEN'S CONCERNS IN THIS PROCEEDING?

A. Yes. In Docket No. G007,011/GR-10-977, Mr. Heinen concluded in his Direct Testimony that MERC had provided adequate observations to conduct an appropriate statistical analysis using the Zero-Intercept method for distribution mains. Additionally, Mr. Heinen continued to express concerns regarding the regression analysis for transmission mains and recommended that should MERC wish to utilize a Zero-Intercept analysis in future proceedings for transmission mains, it "should provide any, and all, regression outputs, along with all supporting input data, in its initial rate case filing along with sufficient written testimony to fully explain this technique and why it was used by MERC to calculate these costs" (Docket No. G007,011/GR-10-977, Heinen Direct, p.71, lines 14-16). Given that MERC is classifying transmission mains 100% to demand and no longer utilizing a Zero-Intercept regression analysis within its COSS for transmission mains, it believes Mr. Heinen's concerns from Docket No. G007-,011/GR-10-977 have been addressed.

V. ALLOCATION OF PRODUCTION COSTS

Q. HOW DOES MERC ALLOCATE PRODUCTION COSTS TO CUSTOMERS WITHIN THE CCOSS?

A. MERC first classifies production costs within the appropriate categories of Purchased Gas, Gas Supply Acquisition, Daily Firm Capacity, and Demand. Once assigned to these four classifications, costs are then allocated to the rate schedules based on the Commodity Cost allocator for Purchased Gas, the Sales allocator for Gas Supply Acquisition costs, the DFC allocator for Daily Firm Capacity costs, or the Firm Peak Demand allocator for Demand costs.

VI. ALLOCATION OF CUSTOMER COSTS

Q. HOW DOES MERC ALLOCATE CUSTOMER COSTS TO EACH RATE SCHEDULE WITHIN THE CCOSS?

A. In general, customer costs are allocated based on total annual fixed charge counts by rate schedule.

Costs that could be directly related to customers that utilize distribution and transmission service were identified and allocated directly to those customers based upon a specific Customer – Transmission allocator. Costs that could be directly related to General Service and Small Volume customers were identified and allocated directly to those customers based upon a specific Customer – GS & Small Volume allocator. Costs that could be directly related to transportation customers were identified and allocated directly to those customers based upon a specific Transport Customer allocator. Costs that could be directly related to residential or C&I customers, such as Account 904: Uncollectibles Expense, were identified and allocated directly to those customers based upon a specific Direct – Residential, or Direct – C&I allocator. All of these specific allocators are shown on Informational Requirement Document 12, Schedule 3. Costs that could be directly related to SLV transportation customers served by Northern Natural Gas were identified within MERC's Accounting system and allocated directly to those customers.

VII. ALLOCATION OF ADMINISTRATIVE AND GENERAL COSTS

Q. HOW DOES MERC ALLOCATE ADMINISTRATIVE AND GENERAL COSTS TO EACH RATE SCHEDULE WITHIN THE CCOSS?

A. First, a piece of Administrative and General ("A&G") costs are directly allocated to transportation customers based upon a proportional split of direct assigned O&M Customer Accounts Expense (Accounts 901-905) to Total O&M Expense (excluding any direct assigned costs or purchased gas costs). Once the transportation direct assigned piece of A&G is calculated, the remaining A&G is classified to Gas Supply Acquisition, Daily Firm Capacity, Demand and Customer classifications according to the proportion of Total O&M Expense (excluding any direct assigned costs or purchased gas costs), which can be found on Line 35 of Informational Requirement Document 12, Schedule 1, page 39. Once classified, the Gas Supply Acquisition costs are then allocated to rate schedules based upon the Sales allocator, the Daily Firm Capacity costs are allocated based upon the DFC allocator, the Demand costs are allocated based upon the Weighted Peak Demand allocator, and the Customer costs are allocated based upon the Customer allocator. The direct assigned transportation A&G costs are allocated to only the transportation rate schedules based upon the Transport Customer allocator.

VIII. UNIQUE ALLOCATIONS

Q. PLEASE DESCRIBE THE REMAINING COMPONENTS OF THE CCOSS THAT HAVE UNIQUE ALLOCATORS.

A. The remaining components of the CCOSS which have unique allocators are as follows:

1. Taxes other than Income Taxes ("TOTIT") associated with Real Estate & Property, Unauthorized Insurance Tax, Excise Tax and Use Tax, Income Taxes, and Miscellaneous Revenues in Account 493 were allocated to the rate schedules based upon a Rate Base allocator, which was created on pages 1 - 3 of Informational Requirement Document 12, Schedule 1.

2. TOTIT relating to Unemployment Compensation, IBS Payroll Tax, and Retirement Benefits are allocated to the rate schedules based upon a Salaries and Wages allocator, which can be found in Informational Requirement Document 12, Schedule 3.

3. Distribution related investment and costs in Accounts 301, 302, 303, 374 and 375 are allocated to the rate schedules based upon a Distribution Plant allocator, which is based upon distribution plant investment in Accounts 376 through 385. The Distribution Plant allocator can be found in Informational Requirement Document 12, Schedule 1, page 34.

IX. NATURAL GAS COST OF SERVICE STUDIES

Q. PLEASE DESCRIBE SCHEDULE 1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1 shows the summarized results of MERC's natural gas embedded CCOSS for the Minnesota service territory for the 2014 proposed test year expenses. Schedule 1 consists of 39 pages, and meets the requirements of the Commission's Final Order in Docket No. G-007,011/GR-11-997, requiring that MERC allocate income taxes on the basis of taxable income by class that fully and only reflects the class cost of service study.

Pages 1 through 3 summarize the various components of the operating income, operating expenses, and rate base to the rate schedules. Line 42 of pages 1 through 3 shows the Rate of Return resulting from operations. Line 54 of pages 1 through 3 shows the amount revenue deficiency by rate class based on the required rate of return on common equity of 10.75%, which is MERC's requested return on common equity in this general rate case proceeding and is supported by the testimony of MERC witness Mr. Paul Moul. Line 56 of pages 1 through 3 shows the percentage of revenue deficiency by rate class with cost of gas excluded. Pages 1 through 3 also include the creation of the allocation methodology for Rate Base, which is used throughout other pages of the CCOSS.

Pages 4 through 6 contain the Operating Revenues by rate schedule based on the rates authorized in MERC's last general rate case proceeding in Docket No. G007,011/GR-10-977.

Pages 7 through 9 contain the Allocation of Operation and Maintenance ("O&M") Expenses. Page 39 contains a detailed breakdown of the classification of O&M Expenses that were utilized on Pages 7 through 9. Page 39 also includes the creation of the classificational methodology titled Total O&M (excluding direct assigned and purchased gas cost related items), which is used to classify costs in other areas of the CCOSS. Direct allocations were made whenever possible.

Pages 10 through 12 contain the Allocation of Depreciation Expenses, with General expense apportioned. Page 38 contains a detailed breakdown of the classification of Depreciation Expenses that was utilized on Pages 10 through 12.

Pages 13 through 15 contain the Allocation of Taxes Other Than Income Taxes.

Pages 16 through 18 contain the Allocation of Other Income and Adjustments, for both Before Income Taxes as well as After Income Taxes. In the 2014 proposed test year there were no Other Income and Adjustments.

Pages 19 through 21 contain the Allocation of Plant in Service, with General expense apportioned. Page 34 contains a detailed breakdown of the classification of Plant in Service that was utilized on Pages 19 through 21. Page 34 also includes the creation of the classificational methodologies for Distribution Plant and Gross Plant, which are used throughout other pages of the CCOSS.

Pages 22 through 24 contain the Allocation of Depreciation Reserve – Straight Line, with General expense apportioned. Page 35 contains a detailed breakdown of the classification of Depreciation Reserve – Straight Line that was utilized on Pages 22 through 24.

Pages 25 through 27 contain the Allocation of Depreciation Reserve – Deferred Taxes, with General expense apportioned. Page 36 contains a detailed breakdown of the classification of Depreciation Reserve – Deferred Taxes that was utilized on Pages 25 through 27.

Pages 28 through 30 contain the Allocation of Construction Work in Progress, with General expense apportioned. Page 37 contains a detailed breakdown of the classification of Construction Work in Progress that was utilized on Pages 28 through 30.

Pages 31 through 33 contain the Allocation of Other Rate Base Components. The Working Capital methodology utilized on Pages 31 and 33 follows the Lead Lag Study approach, which is the suggested methodology of the Commission.

Q. CAN YOU PLEASE DESCRIBE SCHEDULE 2 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Schedule 2 contains a functionalized and classified revenue requirement and rate base allocation for each of the rate schedules. There is one page of information for each rate schedule. Schedule 2 consists of 26 pages

Q. CAN YOU PLEASE DESCRIBE SCHEDULE 3 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Schedule 3 contains a summary of the external allocation methodologies used within the CCOSS shown in Informational Requirement Document 12, Schedule 1. Schedule 3 consists of 6 pages.

Pages 1 through 3 show the development of the following allocation factors:

1. The Group Demand allocation, which consists of the monthly peak of each rate schedule (group, or class), including transportation, to simulate distribution system peaking (based on the highest one month of demand for each group),

2. The Weighted Peak Demand allocation, which consists of the group demand for each rate schedule, including transportation but excluding rate schedules whose customers that are directly connected to the Interstate Pipeline, and weighting those demands based on annual therm throughput,

3. The Firm Peak Demand allocation, which consists of the weighted peak demand for rate schedules that take 100% firm service,

4. The Account 378 Demand allocation, which consists of the weighted peak demand for rate schedules that are General Service and Small Volume rate schedules,

5. The Account 385 Demand allocation, which consists of the weighted peak demand for rate schedules that are industrial sized, which consist of the Large Volume and Super Large Volume rate schedules, but excluding rate schedules whose customers that are directly connected to the Interstate Pipeline,

6. Sales allocation, which is the sales of all customers, not including transportation sales, and

7. The Therm Throughput allocation, which is the sales of all customers, including transportation sales.

Pages 4 through 6 show the development of the following allocation factors:

1. The DFC allocation, which consists of the annual summation, utilizing an average of 30 days per month for 12 months, of the daily firm capacity nominations of the rate schedules that are Joint Firm/Interruptible,

2. The Customer allocation factor, which is based on total yearly bill counts for all rate schedules,

3. The Customer – Transmission allocation, which is based on total yearly bill counts of all rate schedules excluding rate schedules whose customers that are directly connected, or are extremely close, to the Interstate Pipeline,

4. The Customer – GS & Small Volume allocation, which is based on total yearly bill counts of the General Service and Small Volume rate schedules,

5. The Direct – Residential allocation, which is based on total yearly bill counts of the Residential rate schedules,

6. The Direct – C&I allocation, which is based on total yearly bill counts of the non-Residential rate schedules,

7. The Services allocation, which is based on total annual bill counts for all rate schedules, excluding rate schedules whose customers that are directly connected, or extremely close, to the Interstate Pipeline, and utilizes an Average Cost Per Foot for Services weighting factor,

8. The Meters allocation, which is based on total annual meter counts for all rate schedules, excluding rate schedules whose customers that are directly connected, or are extremely close, to the Interstate Pipeline, and utilizes a Cost Per Customer for Meters weighting factor,

9. The Transport Customer allocation factor, which is based on the total yearly meter counts for transportation rate schedules,

10. The Commodity Cost allocation, which is based on the purchased cost of gas for each rate schedule,

11. The Salaries and Wages functional allocation factor, and

12. The Salaries and Wages rate schedule allocation factor.

Q. CAN YOU PLEASE EXPLAIN THE SIGNIFICANCE OF THE FAR RIGHT COLUMN LABELED "SOURCE OR ALLOCATION FACTOR" ON EACH PAGE OF SCHEDULE 3 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. The far right column labeled "Source or Allocation Factor" represents the name that was given to each of the specific allocators created within Schedule 3. Each of these names shown in the "Source or Allocation Factor" column is what is used throughout the CCOSS in Informational Requirement Document 12, Schedule 1 when referencing the allocation methodology that was used to allocate costs to the rate schedules.

Q. PLEASE DESCRIBE INFORMATIONAL REQUIREMENT DOCUMENT 12, SCHEDULE 4.

A. Schedule 4 shows the cost of service for the rate schedules by billing unit based upon the CCOSS presented in Schedule 1. Schedule 4 consists of three pages.

Page 1 of Schedule 4 is a summary of all the billing unit costs by rate schedule, broken down into the billing units of Per Meter Fixed Charge, Enhanced Administrative Charge, Volumetric Rate, Gas Supply Acquisition Rate, and Daily Firm Capacity Rate. The column titled Total Per Meter Fixed Charge is the summation Columns [B] and [C] for each rate schedule. The column titled Total Therm Rate is the summation of Columns [E] and [F] for each rate schedule.

Page 2 of Schedule 4 shows the creation of the Volumetric Rate, the Daily Firm Capacity Rate, and Gas Supply Acquisition Rate for each of the rate schedules. Therm Throughput and Daily Firm Capacity values were taken from Informational Requirement Document 12, Schedule 3. Demand Costs, Daily Firm Capacity Costs, and Gas Supply Acquisition Costs were taken from the respective columns of Informational Requirement Document 12, Schedule 2 on each of the respective pages for the rate schedules.

Page 3 of Schedule 4 shows the creation of the Fixed Charge and Enhanced Administrative Charge for each of the rate schedules. Meter Counts were taken from Informational Requirement Document 12, Schedule 3. Customer Costs and Enhanced Administrative Costs were taken from the respective columns of Informational Requirement Document 12, Schedule 2 on each of the respective pages for the rate schedules.

Q. PLEASE DESCRIBE SCHEDULE 5 INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5 contains the detail of the Distribution Mains Zero-Intercept study and consists of 25 pages. When conducting the Zero-Intercept study, a second study was performed adjusting for any outliers found within the data set. The Zero-Intercept study was performed utilizing historical data for the year ending December 31, 2012.

Q. PLEASE DESCRIBE SCHEDULE 6 OF INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 6 shows an incremental cost analysis for MERC's Super Large Volume customers. The result of the analysis is utilized by MERC witness Mr. Greg Walters to demonstrate that the Super Large Volume customer classes are covering their incremental cost of service.

Q. PLEASE DESCRIBE SCHEDULE 7 OF INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. As required by Order Point 8 of the Commission's Final Order in Docket No. G-007,011/GR-08-835, Schedule 7 identifies and describes each allocation method used in the CCOSS. Schedule 7 also details the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered.

Q. PLEASE DESCRIBE SCHEDULE 8 OF INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 8 provides the determination of the appropriate Enhanced Administration Monthly Fixed Charge, also known as the Transportation Administration Fee. The Transportation Administration Fee is charged only to Transportation customers to cover the added administrative costs of providing transportation service. The added administrative costs of providing transportation service are caused on a per customer basis; i.e. the costs do not vary with each customer's usage. Therefore the charge was calculated based upon meter counts.

Q. HAS THE TRANSPORTATION ADMINISTRATION FEE CALCULATED FROM THE CCOSS CHANGED SINCE MERC'S LAST RATE CASE FILING?

A. Yes, it has increased from a calculated value of $70.20 in MERC's last rate case Docket No. G007,011/GR-10-977, to a calculated value of $110.11, as shown in Informational Requirement Document 12, Schedule 8.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN THE TRANSPORTATION ADMINISTRATION FEE, AS CALCULATED FROM THE CCOSS?

A. The increase is attributable to increased labor costs attributable to DeMaxx2, which is the telemetering information system. Demaxx2 was updated to conform to federal new pipeline integrity rules for Control Room Management and cyber security. The increase in labor costs to support the current Demaxx2 system for these rules is the primary driver of the transportation administration fee.

Q. PLEASE DESCRIBE SCHEDULE 9 OF INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 9 provides verification that the Rate Base allocation method, which is used in the CCOSS to allocate Income Taxes, follows the Commission's July 13, 2012 Findings of Fact, Conclusions of Law, and Order in Docket No. G-007,011/GR-10-977, which adopts the ALJ's Proposed Order that income taxes be allocated on the basis of taxable income by class that fully and only reflects the class cost of service study.

X. CONCLUSION

Q. IN YOUR OPINION, DOES THE CCOSS PROVIDE A REASONABLE BASIS FOR ESTABLISHING RATES IN THIS CASE?

A. Yes, it does. The CCOSS is a reasonable estimate of revenue requirements by customer class and supports the rates requested in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY ON THE CCOSS AT THIS TIME?

A. Yes, it does.