Direct Testimony
Aaron L. Nelson

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-17-563

Exhibit _____

**Class Cost of Service Studies**

October 13, 2017

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## I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Aaron L. Nelson. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Minnesota Energy Resources Corporation ("MERC" or the "Company").

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

A. I am currently a Project Specialist of WEC Business Services, LLC ("WBS"). Both MERC and WBS are wholly-owned subsidiaries of WEC Energy Group, Inc. ("WEC Energy Group").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration degree, with specializations in management and information systems, from the University of Wisconsin – Eau Claire in December 2011. In December 2016, I received a Master of Science in Management degree, with specialization in financial analysis, from the University of Wisconsin – Milwaukee.

Regarding my professional experience, I accepted a position with We Energies as an analyst in Wholesale Energy and Fuels in January 2012. In October 2016, I assumed my current role in Regulatory Affairs with WBS. My responsibilities include performing cost of service for all of the natural gas utility subsidiaries of WEC Energy Group.

## II. OVERVIEW OF TESTIMONY

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

A. The purpose of my testimony is to describe and present MERC's Class Cost of Service Studies ("CCOSS") for the 2018 proposed test year. I also address compliance with requirements related to cost of service from the Minnesota Public Utilities Commission's ("Commission") prior orders, including from MERC's last rate case in Docket No. G011/GR-15-736 and Order Point 8 from the Commission's Order Approving Rochester Project and Granting Rider Recovery with Conditions in Docket No. G011/M-15-895.

Q. ARE YOU SPONSORING ANY INFORMATIONAL REQUIREMENT DOCUMENTS WITH THIS TESTIMONY?

A. Yes. As required by Minn. R. 7825.4300(C), I am sponsoring Informational Requirement Document 12, which contains MERC's CCOSS for the 2018 proposed test year along with supporting data. Volume 3, Informational Requirement Document 12 contains the following schedules of information:

Schedule 1.0 – Class Cost of Service Results – Zero-Intercept Method

1.1 – Revenue Requirements by Customer Class

1.2 – Billing Unit Cost by Customer Class

1.3 – External Allocators Results

1.4 – Zero-Intercept Study Results

1.5 – Incremental Cost Analysis – Super Large Volume Customers

1.6 –Allocation Methodologies
1.7 – Enhanced Administration Monthly Fixed Charge Results
1.8 – Allocation of Income Taxes
2.0 – Class Cost of Service Results – Minimum-Size Method
2.1 – Revenue Requirements by Customer Class
2.2 – Billing Unit Cost by Customer Class
2.3 – Minimum Size Study Results
2.4 – Incremental Cost Analysis – Super Large Volume Customers
3.0 – Class Cost of Service Results – Basic System Method
3.1 – Revenue Requirements by Customer Class
3.2 – Billing Unit Cost by Customer Class
3.3 – Incremental Cost Analysis – Super Large Volume Customers
4.0 – Class Cost of Service Results – Average and Excess Method
4.1 – Revenue Requirements by Customer Class
4.2 – Billing Unit Cost by Customer Class
4.3 – Incremental Cost Analysis – Super Large Volume Customers
5.0 – Class Cost of Service Results – MERC's existing customer classes
5.1 – Revenue Requirements by Customer Class
5.2 – Billing Unit Cost by Customer Class
5.3 – External Allocators Results
5.4 – Incremental Cost Analysis – Super Large Volume Customers
6.0 – Summary Class Cost of Service Study Results

Q. DOES YOUR TESTIMONY ADDRESS ANY OTHER FILING REQUIREMENTS?

A. Yes, my testimony addresses the following Commission requirements:

First, the Commission's June 29, 2009, Findings of Fact, Conclusions, and Order in Docket No. G007,011/GR-08-835 required that, in future CCOSS filed in general rate cases, MERC must 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. Similarly, in its October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736, the Commission required that, in MERC's next rate case, the Company provide a substantive explanation and justification of its classification and allocation methods. This requirement is addressed below in testimony with support from Schedule 1.6 of Volume 3, Informational Requirement Document 12.

Second, in the Commission's July 13, 2012, Findings of Fact, Conclusions, 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 CCOSS. The Commission affirmatively confirmed this allocation method for MERC in its October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617. Included in Volume 3, Informational Requirement Document 12, Schedules 1.0, 2.0, 3.0 and 4.0 are CCOSSs for MERC that allocate income taxes on the basis of rate base, which, mathematically, is the same method as described above. Schedule 1.8 in Volume 3, Informational Requirement

Document 12, demonstrates 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.

Third, my testimony addresses the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736. The Commission's Order, at Order Point 12, required that MERC, in its next rate case, file four CCOSSs, each varying the method in which distribution mains are classified between commodity, demand, and customer. The four classification methodologies and their corresponding Schedule in Volume 3, Informational Requirement Document 12 include:

- Zero intercept, Schedule 1.0;
- Minimum Size, Schedule 2.0;
- Basic System, Schedule 3.0; and
- Average and Excess, Schedule 4.0.

Fourth, my testimony addresses the Commission's October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617. The Commission's Order, at Order Point 32, required that MERC take the following actions in preparing future class cost of service studies:

- Collect data on additional variables that impact the unit cost of mains installation;
- Avoid aggregating or averaging data and use data at the finest level reasonable;
- Check ordinary-least-squares ("OLS") regression assumptions and correct for violations; and

- Make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

MERC understands these requirements to have been subsumed into Order Point 12 of the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736, which directed MERC, in preparation for its next CCOSS, to:

- Collect project-specific data on installation footage, pipe diameter, and cost;
- Research and, as soon as possible, begin collecting data regarding the retirement of distribution assets at the same project-level detail; and
- In future rate cases, explore the use of this project-specific data in MERC's zero-intercept CCOSS.

Section VI.C.2 of my testimony addresses each of these requirements.

Lastly, I address the Commission's May 5, 2017, Order Approving Rochester Project and Granting Rider Recovery with Conditions in Docket No. G011/M-15-895, which required MERC, in its next general rate case, to provide a discussion and analysis of its current interruptible and transportation rate structure, including cost allocation methodologies, explaining the impact of added Rochester capacity.

Q. ARE THERE ANY CHANGES BETWEEN 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. G011/GR-15-736?

A. Yes. MERC made the following changes to its recommended CCOSS in this rate-case filing:

- MERC's proposed CCOSS incorporates new customer classes, as discussed in the Direct Testimonies of Mr. Seth DeMerritt and Ms. Amber Lee.
- MERC has allocated demand-related production costs by Coincident Demand rather than Non-Coincident Demand.

Additionally, as discussed above, in compliance with the Commission's Order in MERC's last general rate case, Docket No. G011/GR-15-736, MERC is providing two additional CCOSSs — one that utilizes the Basic System method to classify distribution mains to the customer and demand classifications and one that utilizes the Average and Excess ("A&E") method. Volume 3, Informational Requirement Document 12, Schedules 3.0 and 4.0 provide these additional CCOSSs. Notably, however, while MERC presents a number of additional CCOSSs to comply with the Commission's order to provide this additional information, MERC is recommending that the Commission rely on its zero-intercept CCOSS, found in Schedule 1.0 of Volume 3, Informational Requirement Document 12, for purposes of setting rates in this proceeding.

Q. HOW DO THE NEW CUSTOMER CLASSES PROPOSED BY MERC IMPACT ITS CCOSS?

A. A change in customer classes requires an update to the customer classes in a CCOSS. Specifically, in MERC's case, MERC updated the names of the customer classes in its CCOSS, consistent with the customer classes it is proposing in this rate-case filing, as discussed in greater detail in the Direct Testimony of Amber Lee. For example, MERC's current SVI-NNG Transport customer class was replaced with NNG C&I INT Class 3 (transport) and NNG C&I INT Class 4 (transport). Consistent with MERC's last rate case, MERC's NNG customer classes are inclusive of MERC's Albert Lea customers. Cost allocations in MERC's proposed CCOSSs did not change from prior CCOSSs (e.g., sales customers still receive cost allocations related to purchased gas costs and gas supply acquisition costs). Again, MERC's proposed CCOSSs can be found in Schedules 1.0, 2.0, 3.0 and 4.0 of Volume 3, Informational Requirement Document 12. Additionally, MERC provided a CCOSS based on the customer classes currently in place. This CCOSS can be found in Schedule 5.0 of Volume 3, Informational Requirement Document 12.

Q. HAVE THE COST ALLOCATIONS RELATED TO ALBERT LEA CUSTOMER CLASSES RECENTLY BEEN REVIEWED BY THE COMMISSION?

A. Yes. In MERC's last rate case, Docket No. G011/GR-15-736, the issue of whether MERC should be required to conduct a separate CCOSS for serving customers who were formerly served by Interstate Power and Light Company ("IPL") and are now served by MERC was addressed. In that proceeding, the OAG argued that MERC's CCOSS should be given no weight with respect to the costs caused by former IPL customers since MERC had not conducted a separate study. As reflected in the Commission's Findings of Fact, Conclusions, and Order in that proceeding,

> The Administrative Law Judge rejected the OAG's argument that MERC erred in failing to distinguish between customers in service areas formerly served by IPL and the rest of its customers. The record revealed no instance in which the Commission had required a separate cost study for customers in a newly acquired service area. Moreover, the Administrative Law Judge cited testimony

> from MERC and the Department disputing the suggestion that IPL's former customers had different costs than MERC's other customers, and stating that MERC's CCOSSs accounted for the characteristics of the former IPL customers.[1]

The Commission agreed, finding

> …no basis for the OAG's claim that MERC should have excluded former IPL customers from MERC's cost studies. MERC provided credible testimony that customers in the Albert Lea area are relatively homogenous with other MERC customers in their respective customer classes, and that MERC's CCOSSs appropriately accounted for the load profiles of the Albert Lea customers.[2]

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, in Section III, I provide a discussion of the purpose and process of performing a CCOSS. In Sections IV and V, I discuss the classification of production costs and transmission costs. In Section VI, I discuss the classification and allocation of distribution costs under a minimum-size method, zero-intercept method, Basic System method, and A&E method and MERC's conclusions and recommendations based on evaluation of these alternative methodological approaches to classifying and allocating distribution costs. In Section VII, I discuss the classification and allocation of customer costs. In Section VIII, I discuss the classification and allocation of administrative and general costs. In Section IX and X, I discuss the allocation of taxes. In Section XI, I provide a discussion and analysis of MERC's interruptible and transportation rate

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[1] *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Oct. 28, 2014).

[2] *Id.*

structure cost allocation methodologies and address the impact of excess Rochester capacity.  In Section XII, I provide an overview of the workpapers I am supporting.

## III. GAS CLASS COST OF SERVICE STUDY PURPOSE AND PROCESS

### A. Purpose

Q. WHAT IS THE PURPOSE OF PERFORMING A CCOSS?

A. The purpose of a CCOSS is to identify the revenues, costs, and profitability for each class of service, as required by Minn. R. 7825.4300(C).  The CCOSS 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. In general, preparing a CCOSS involves three steps:  (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. COULD YOU PLEASE EXPLAIN COST FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION?

A. Cost functionalization identifies and separates plant and expenses into functions within a utility.  Generally, functions used in a gas CCOSS include:  (1) Production; (2) Storage; (3) Transmission; (4) Distribution; (5) Customer; and (6) Administrative and General. Cost classification further assigns functionalized plant and expenses to categories based on whether they are related to (1) energy or commodity; (2) demand or capacity; or (3) customers.  For example, commodity costs are those that vary with the amount of energy supplied; demand costs are influenced by the sizing of facilities to meet peak customer demands; and customer costs are those that vary with the number of customers connected to the distribution system. Cost allocation further assigns plant and expenses to customer groups or classes based on how each class causes costs to be incurred.

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

A. The Direct Testimony of Ms. Amber Lee presents MERC's proposed rate design, based in part on the results of the CCOSS.

**B. <u>Process</u>**

Q. PLEASE DESCRIBE MERC'S APPROACH IN THE DEVELOPMENT OF ITS CCOSS.

A. In the development of MERC's CCOSS, MERC primarily relied upon guidance from the following industry-accepted sources: (1) American Gas Association ("AGA"), Gas Rate Fundamentals, 1987; (2) National Association of Regulatory Utility Commissioners ("NARUC"), Staff Subcommittee on Gas, Gas Distribution Rate Design Manual, 1989; and (3) NARUC, Staff Subcommittees on Electricity and Economics, Electric Utility Cost Allocation Manual, 1992. Consistent with these manuals, MERC's CCOSSs attempt to associate costs with customer classes based on cost causation. That is, "to attribute costs to different categories of customers based on how those customers cause costs to be incurred".[3] There are some cases where a direct association of costs to

[3] NARUC, Electric Utility Cost Allocation Manual, at 12 (1992).

customers exists based on causation.[4] 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. Distribution system costs fall into this category.[5]

Q. HOW DID MERC FUNCTIONALIZE COSTS?

A. In general, the basis for functionalizing costs is the Uniform System of Accounts ("USOA") published by the Federal Energy Regulatory Commission ("FERC"). MERC assigned costs to functions following the FERC USOA. This approach is consistent with the guidelines outlined by the AGA and NARUC.[6] MERC's CCOSS functional cost categories include: (1) Production; (2) Transmission; (3) Distribution; (4) Customer; and (5) Administrative and General.

Q. PLEASE DESCRIBE MERC'S PROCESS FOR CLASSIFYING COSTS.

A. All costs are classified by whether they are related to commodity, demand, or customers. MERC's CCOSS classification categories include: (1) Commodity, with sub

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[4] AGA, Gas Rate Fundamentals at 135-37 (1987).

[5] NARUC, Electric Utility Cost Allocation Manual at 90 (1992).

[6] AGA, Gas Rate Fundamentals at 135 (1987); NARUC, Electric Utility Cost Allocation Manual at 19 (1992); NARUC, Gas Distribution Rate Design Manual at 21-22 (1989).

classifications (a) Purchased Gas Cost and (b) Gas Supply Acquisition Cost; (2) Demand, with sub classifications (a) Firm Demand and (b) Interruptible Demand; and (3) Customer, with sub classifications (a) Customer, (b) Enhanced Other Services, and (c) Direct. Commodity-related costs are costs incurred that vary with the amount of energy supplied. The cost of gas, oftentimes referred to as gas purchases or purchased gas cost, is an example of a commodity-related cost. Demand-related costs are costs that are incurred to meet peak customer demands. The cost of a gas transmission main is an example of a demand-related cost. Customer-related costs are costs incurred as customers are connected to the distribution system, regardless of the amount of energy they consume or demand.

Q. PLEASE DESCRIBE MERC'S PROCESS FOR ALLOCATING COSTS.

A. MERC's cost allocation further assigns costs to customer groups or classes, on the basis of cost causation. Each classified cost element is assigned an allocation factor that reflects the cost causation principle of the cost element. For example, gas supply acquisition costs, which have a direct relationship to customers' sales, are allocated to customer classes by MERC's Sales allocator. Direct assignment of values to the appropriate customer classes was conducted whenever possible, as recommended by both the AGA and NARUC.[7] An overview of MERC's allocators can also be found in Schedule 1.6 of Volume 3, Informational Requirement Document 12. Additionally, the results of MERC's allocator calculations can be found in Schedule 1.3 of Volume 3, Informational Requirement Document 12.

[7] AGA, Gas Rate Fundamentals at 140 (1987); NARUC, Gas Distribution Rate Design Manual at 31 (1989).

## IV. CLASSIFICATION AND ALLOCATION OF PRODUCTION COSTS

Q. HOW ARE MERC'S PRODUCTION COSTS CLASSIFIED?

A. Production costs are those costs that relate to producing, purchasing, or manufacturing gas. MERC classifies production costs within the appropriate categories of Purchased Gas, Gas Supply Acquisition, Firm Demand, and Interruptible Demand. Production costs that vary with the amount of gas supplied are classified as commodity-related and further broken down into categories of Purchased Gas Cost and Gas Supply Acquisition. Examples include FERC Accounts 804, Natural Gas Purchases, and 813, Other Gas Supplies Expense. These costs are incurred based on the amount of gas supplied. Production costs that do not vary with the amount of gas supplied are classified as demand-related and further broken down into categories of firm capacity-related or interruptible capacity-related. Examples include FERC Accounts 735, Liquefied Gas Production, and 756, Field Measuring & Regulation Station. These costs are incurred while meeting peak demands on the system.

Q. HOW ARE MERC'S COMMODITY-RELATED PRODUCTION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. All commodity-related production costs are allocated to customer classes by a commodity allocator, based on the quantity of gas consumed. This allocation methodology is appropriate per the NARUC Gas Distribution Rate Design Manual.[8] Cost of Gas-related Purchased Gas costs are allocated to customer classes by a

[8] NARUC, Gas Distribution Rate Design Manual at 25 (1989).

Commodity Cost allocator. This allocator is based on the direct assigned purchased cost of gas for each customer class. Gas Supply Acquisition-related costs are allocated to customer classes by a Sales allocator because these costs cannot be directly assigned but vary with the amount of gas supplied.

Q. HOW ARE MERC'S DEMAND-RELATED PRODUCTION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. All demand-related production costs are allocated to customer classes by a coincident peak demand allocator. This allocation methodology is appropriate because these costs are incurred to meet peak demand requirements. Therefore, customer classes should be allocated their share of costs based on each class's contribution to the system maximum peak.

## V. CLASSIFICATION AND ALLOCATION OF TRANSMISSION COSTS

Q. HOW ARE MERC'S TRANSMISSION COSTS CLASSIFIED?

A. Transmission costs are incurred to transport wholesale natural gas from interstate pipelines to MERC's distribution system. All transmission-related costs are classified as demand related as these assets are in place for MERC to provide transmission service, and these assets are sized to meet MERC's peak system demand. Examples include plant in FERC Accounts 367, Mains, and 369, Measuring and Regulating Station Equipment. Classifying transmission costs in this manner is consistent with the practice outlined by the AGA.[9]

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[9] AGA, Gas Rate Fundamentals at 197-201 (1987).

Q. HOW ARE MERC'S TRANSMISSION COSTS ALLOCATED TO CUSTOMER CLASSES?

A. Because all of MERC's transmission costs are classified as demand related, all of MERC's transmission costs are allocated to customer classes by a demand allocator. Firm transmission costs are allocated to customer classes by a Peak Demand-Firm allocator and interruptible transmission costs are allocated to customer classes by a Weighted Peak Demand-Interrupt allocator. These two allocators are appropriate because these costs are incurred to meet peak demand requirements.

The only customer classes excluded from allocations of MERC's transmission costs are the Farm Tap classes. It is appropriate to exclude Farm Tap classes from the allocations of transmission costs because MERC's transmission assets currently do not serve Farm Tap customers. Each Farm Tap customer is instead directly connected to an interstate transmission pipeline.

## VI. CLASSIFICATION AND ALLOCATION OF DISTRIBUTION COSTS

### A. Overview

Q. HOW ARE MERC'S DISTRIBUTION COSTS CLASSIFIED?

A. There are two significant cost causation relationships for distribution-related costs. As the Commission has previously recognized, a gas utility's distribution plant is designed both (1) to meet system capacity needs and (2) to connect customers regardless of their individual capacity needs.[10] Some distribution-related costs are incurred in order for customers to be connected to the distribution system. Because these distribution-related costs vary with the number of customers on the system, they are classified as customer related. An example of customer-related distribution costs are FERC Accounts 380 and 381, services and metering equipment. Other distribution-related costs are incurred to meet peak customer demands. These distribution-related costs are classified as demand-related. An example of demand-related distribution costs is FERC Account 379, Measuring & Regulation Equipment. Other distribution-related costs, such as FERC Account 376, gas distribution mains, are influenced by both customer and demand components, and require further analysis to derive an appropriate ratio that allocates costs to multiple classifications.

Q. WHAT FACTORS OF GAS DISTRIBUTION MAINS ARE INFLUENCED BY DEMAND ON A UTILITY'S SYSTEM?

A. Gas distribution mains are an extensive network of small (e.g., two-inch) to medium (e.g., twelve-inch) pipe responsible for delivering natural gas to consumers within a specific area. When gas distribution mains are installed, they are engineered to meet peak demand reliably and safely. A main will not be installed if it is incapable of serving peak demand. Therefore, a portion of costs related to gas distribution mains must be classified as demand in a CCOSS.

[10] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33-34 (Oct. 31, 2016).

Q. WHAT FACTORS OF GAS DISTRIBUTION MAINS ARE INFLUENCED BY THE NUMBER OF CUSTOMERS CONNECTED TO A UTILITY'S SYSTEM?

A. Some costs of installing gas distribution mains are incurred simply to connect a customer or group of customers to the system. For example, the quantity or length of pipe installed. When installing gas distribution main, the size or diameter of that particular pipe is determined in part by the peak demands it will be responsible for meeting. However, total quantity of pipe installed at a utility is influenced by the need to expand the distribution system in order to connect customers.

Q. WHAT METHODS EXIST FOR SEPARATING THE CUSTOMER-RELATED PORTION FROM THE DEMAND-RELATED PORTION OF A GAS DISTRIBUTION MAIN?

A. As described by the AGA, some cost elements of a utility cannot be classified directly to a single classification category.[11] Today there are two commonly used studies for determining the customer- and demand-related portions of gas distribution mains: (1) the minimum-size study; and (2) the zero-intercept study. Both studies are referred to as a "minimum-system study", and as its name suggests, each study derives a "minimum system". The minimum system consists of the minimum amount of fixed investment required to connect customers to the system regardless of their gas usage or demand (i.e., the customer-related portion). Costs in excess of the minimum system are related to the demand imposed on the system by those customers (i.e., the demand-related portion).

[11] AGA, Gas Rate Fundamentals at 137 (1987).

Account 376, gas distribution mains, is an example of one such cost element that is appropriate to separate between the customer-related and demand-related components. A minimum-system study would be used to appropriately allocate gas distribution main costs between the customer-related classification and the demand-related classifications in a CCOSS.

Q. DOES A MINIMUM-SYSTEM STUDY CHANGE THE TOTAL AMOUNT OF DISTRIBUTION MAIN INVESTMENT AND COSTS WITHIN A CCOSS?

A. No, a minimum-system study does not change or have any impact on the total amount of distribution main investment and costs being recovered in MERC's revenue requirements within a CCOSS. It is simply a method used to allocate the total investment between the customer-related classification and demand-related classification.

Q. DID MERC PERFORM A MINIMUM-SYSTEM STUDY IN THIS RATE-CASE FILING?

A. Yes. As required by the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736, MERC performed both a minimum-size study and a zero-intercept study to derive the ratio of customer- and demand-related costs for FERC Account 376, gas distribution mains. MERC's minimum-size CCOSS and zero-intercept CCOSS are described below in sections VI.B and VI.C, respectively.

Q. WAS MERC ORDERED TO USE OTHER METHODS TO CALCULATE THE RATIO OF CUSTOMER AND DEMAND RELATED COSTS FOR FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. Yes. The Commission's October 31, 2016 Findings of Fact, Conclusions, and Order in Docket No. G-011/GR-15-736 required MERC, in its next rate case, to submit two additional CCOSSs: (1) Basic System; and (2) Average &Excess ("A&E"). MERC's Basic System CCOSS and A&E CCOSS are described below in section VI.D and VI.E, respectively.

Q. WHAT VARIABLES DID MERC WORK WITH WHEN PERFORMING ITS FOUR MINIMUM-SYSTEM STUDIES?

A. MERC obtained two data sets from its Plant Accounting System ("Accounting System"): (1) project-level data and (2) non-project-level data. The variables included in the project-level dataset include: (1) project number (i.e., work order); (2) pipe material; (3) pipe diameter; (4) quantity installed; (5) year of installation; (6) total book cost; and (7) total current cost. In addition, MERC calculated three additional variables for use in its zero-intercept study: (1) pipe diameter squared, by squaring the pipe diameter variable; (2) log current unit cost, by taking the log of current unit cost; and (3) square root of current unit cost, by taking the square root of current unit cost. Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, contains the project-level data MERC utilized in its minimum system studies.

The variables included in the non-project level data include: (1) pipe material; (2) pipe diameter; (3) taxing district; (4) quantity installed; (5) year of installation; (6) total book cost; and (7) total current cost. In addition, MERC calculated two additional variables for use in its zero-intercept study: (1) pipe diameter squared, by squaring the pipe diameter variable, and (2) log current unit cost, by taking the log of current unit cost. Table 1 in Volume 4, Nelson Workpapers, contains the non-project level data that MERC utilized in its minimum-system studies. Additionally, the data in Table 1 of Volume 4, Nelson Workpapers, is in the same format and level used in MERC's prior proceedings.

Q. DID MERC UTILIZE BOOK COST WHILE CALCULATING ITS MINIMUM-SYSTEM STUDIES?

A. No. MERC utilized current cost while performing its minimum-system studies.

Q. WHY DID MERC UTILIZE CURRENT COST IN ITS CALCULATION OF AVERAGE UNIT COST?

A. The book cost of distribution main installations maintained in MERC's Accounting System for a given year consists of the total of material costs, labor costs, and overhead and other costs, if any, that were attributable to all of the projects completed in that given year. Comparing the book cost of distribution main installations performed in 1965, for example, would not provide an accurate comparison with distribution main installations performed in 2016, as material prices, labor prices, installation standards, and inflationary factors were generally very different in 1965 than they were in 2016. Therefore, while "normally the average book cost for each piece of equipment determines the price of all installed units"[12], current cost is the better measure in this instance.

Q. HAS CURRENT COST RECENTLY BEEN REVIEWED BY THE COMMISSION IN OTHER MINNESOTA CASES?

A. Yes. In CenterPoint Energy's ("CPE") 2015 rate case in Docket No. G008/GR-15-424, the Commission adopted the ALJ's findings that, for both a zero-intercept study and a minimum-size study, original cost data should be adjusted to current dollars so that the system can be valued accurately.[13]

Q. HOW DID MERC CALCULATE AVERAGE CURRENT COST?

A. MERC utilized the Handy-Whitman Index of Public Utility Construction Costs ("H-W Index") to adjust historic book cost to current cost. Applying the H-W Index to book cost by year of installation provided a way to meaningfully compare costs in a given year to costs of a different year, for example, a 1965 book cost to a 2016 book cost. This is especially important when calculating an average unit cost for use in a minimum-system study, as the average unit cost of each pipe size for MERC is the average of distribution main installations over a 60+ year period.

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[12] NARUC, Electric Utility Cost Allocation Manual at 90-91 (1992).

[13] *In the Matter of the Application of CenterPoint Energy Res. Corp. for Auth. to Increase Nat. Gas Rates in Minn.*, Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 56 (June 3, 2016) ("Given that the Company's mains have been installed at various times over a more-than-100-year period, logic suggests that, for both a zero-intercept study and a minimum-size study, the original cost data should be adjusted to current dollars so that the system can be valued accurately.").

MERC then calculated the average current unit cost as (1) total current cost, grouped by material type and pipe diameter, divided by (2) total quantity (in feet) installed, also grouped by material type and pipe diameter.

Q. WHAT IS THE H-W INDEX?

A. The H-W Index is a widely-accepted and reliable index that will trend historic, or original, book cost records to estimate reproduction or current cost records at prevailing prices. The H-W Index provides the level of costs (stated as cost index values) for different types of utility construction for each year since 1912, and for different geographic locations throughout the 48 contiguous states. The indexes are provided consistent with the FERC USOA, such that they can be applied against the historic book cost of specific utility assets, such as gas distribution mains. "The use of indexes for an appropriate property item or group will provide a reliable guide to changes in cost. . . . [t]he [H-W] Index will furnish a yardstick for the fluctuations in value of property.[14] The H-W Index takes into consideration factors such as wage rates, cost-of-living, material costs, and equipment costs, as well as the proportions of basic materials, labor, equipment, and other cost components. In its minimum-system studies, MERC utilized H-W Index values developed for Gas Utility Construction, FERC Account 376, gas distribution mains, and the North Central geographic region, which is inclusive of the State of Minnesota.

[14] The Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 181 at iv (2015).

**B. Minimum-size Study**

Q. HAS MERC BEEN REQUIRED BY THE COMMISSION TO CONDUCT A MINIMUM-SIZE STUDY AND PERFORM A CCOSS UTILIZING THE RESULTS OF THAT MINIMUM-SIZE STUDY?

A. Yes. The Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736 required that MERC, in its next rate case, submit a minimum-size CCOSS. The results of MERC's minimum-size CCOSS can be found in Schedule 2.0 of Volume 3, Informational Requirement Document 12.

Q. WHAT IS A MINIMUM-SIZE STUDY?

A. A minimum-size study assumes "that a minimum-size distribution system can be built to serve the minimum loading requirements of the customer"[15].

Q. HOW IS A MINIMUM-SIZE STUDY CALCULATED?

A. To conduct a minimum-size study, one must determine: (1) what is the minimum-sized piece of equipment (in this instance, the smallest distribution pipe currently installed by the utility), and (2) the cost of that minimum-sized piece of equipment (in this instance, average unit cost). The average unit cost is then multiplied by the quantities of distribution mains currently installed by the utility to arrive at Total Minimum System Cost. Total Minimum System Cost divided by Total System Cost is considered to be the ratio of the utility's fixed investment classified as customer-related within the CCOSS.

[15] NARUC, Electric Utility Cost Allocation Manual at 90 (1992).

The remaining balance is considered to be costs in excess of the minimum system and is classified as demand related within the CCOSS.[16]

Q. HAVE ANY CONCERNS BEEN NOTED IN PAST DOCKETS WITH RESPECT TO MINIMUM-SIZE STUDIES?

A. Yes. The Commission has noted that minimum-size studies, which calculate customer cost on the basis of a hypothetical distribution plant of some minimum size greater than zero, would be expected to overestimate customer costs. MERC agrees with this assessment, as further described and explained later in this testimony.

Q. DID MERC UTILIZE THE DATA FROM TABLE 1 IN VOLUME 4, NELSON WORKPAPERS, IN ITS MINIMUM-SIZE STUDY?

A. Yes.

Q. HOW DID MERC DETERMINE ITS MINIMUM-SIZED PIPE FOR BOTH PLASTIC AND STEEL INSTALLATIONS?

A. MERC believes it is appropriate to conduct the minimum-size study based on MERC's current installation standards because a minimum-size study is going to be used within the CCOSS, which not only portrays data that is based on a forecasted test year but is also premised on creating an accurate cost causation portrayal of MERC's current customers. MERC's installation standards take into consideration current industry standards and

[16] NARUC, Electric Utility Cost Allocation Manual at 91-92 (1992).

practices and safety measures, as well as what is most appropriate given MERC's service territory.

Q. WHAT IS MERC'S CURRENT INSTALLATION STANDARD FOR PLASTIC AND STEEL PIPE?

Two-inch pipe is MERC's current installation standard for both plastic and steel material. For MERC, 96 percent[17] and 91 percent[18] of all plastic and steel distribution main installations, respectively, are larger than two inches in diameter. As can be seen in the information provided in Schedule 2.3 of Volume 3, Informational Requirement Document 12, MERC does have distribution mains that are smaller than the current installation standard of two inches. These installations typically occurred many years ago when MERC's installation standards were different, and when MERC's customer loads and demands placed on the system were different than what they are today. For the plastic and steel pipe diameters of less than two inches, only 1.7 percent[19] and 0.5 percent[20] of those installations, for plastic and steel, have occurred since the year 2000, and each involved unique construction circumstances that warranted installation of a pipe diameter less than the current installation standard. Additionally, one can see from the minimum-size study shown in Schedule 2.3 of Volume 3, Informational Requirement Document 12, the majority of installation quantities are two inches in size, comprising 70

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[17] Based on quantity, in feet, installed.

[18] Based on quantity, in feet, installed.

[19] Based on quantity, in feet, installed.

[20] Based on quantity, in feet, installed.

percent[21] and 44 percent[22]of total installations for plastic and steel distribution mains, respectively. This confirms that: (a) two-inch pipe is the typical installation size, which mirrors MERC's current installation standard, and (b) to base a minimum-sized pipe on any size less than two inches, which is rarely installed, would not be appropriate.

Q. HOW DID MERC CALCULATE THE COST OF ITS MINIMUM-SIZED PIPE FOR BOTH PLASTIC AND STEEL?

A. First, MERC utilized Microsoft Excel to analyze the data from Table 1 in Volume 4, Nelson Workpapers. Incorrect accounting data or some other abnormality in the data can cause unreliable regression equation results, such as a negative intercept value.[23] In following the guidance of the NARUC Electric Utility Cost Allocation Manual, MERC conducted a review of the accounting data and removed "suspect data."[24] Specifically, MERC removed records that were deemed invalid due to having negative book costs. This data is considered invalid for minimum-system study purposes, as it is invalid to have a negative installation cost. Second, MERC aggregated the quantity (in feet) installed and total current cost, grouped by pipe material and pipe diameter. Once aggregated, total current cost divided by total quantity resulted in an average current cost per pipe material and pipe diameter. As stated earlier, MERC determined its minimum size pipe for both plastic and steel to be two inches. The average current cost for two-inch plastic and steel pipe is $13.06 and $14.14, respectively.

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[21] Based on quantity, in feet, installed.

[22] Based on quantity, in feet, installed.

[23] NARUC, Electric Utility Cost Allocation Manual at 95 (1992).

[24] NARUC, Electric Utility Cost Allocation Manual at 95 (1992).

Q. WHAT WERE THE RESULTS OF MERC'S MINIMUM-SIZE STUDY UTILIZING A TWO-INCH PIPE DIAMETER?

A. MERC calculated Total Current System Costs of $458,902,038, of which $338,148,425 or 73.7 percent calculated to be the Minimum System. The remaining $120,753,614 or 26.3 percent of the Current System Costs represents the demand- or capacity-related cost of the system. The Minimum System cost was derived by multiplying average current unit cost of the minimum-sized pipe for plastic and steel, which is $13.06 and $14.14, respectively, by total quantity of plastic and steel installations, which is 17,395,594 and 7,847,381, respectively. The detailed results of MERC's minimum-size study that utilizes a two-inch pipe can be found on page 1, Schedule 2.3 of Volume 3, Informational Requirement Document 12. The CCOSS results that utilize the two-inch pipe minimum-size study can be found in Schedule 2.0 of Volume 3, Informational Requirement Document 12.

Q. DID MERC CONSIDER OTHER PIPE DIAMETERS FOR ITS MINIMUM-SIZE STUDY?

A. Yes. MERC also considered the smallest-sized pipe currently installed in its service territory, which is 0.75 inches.

Q. WHAT WERE THE RESULTS OF MERC'S MINIMUM-SIZE STUDY UTILIZING A 0.75-INCH PIPE DIAMETER?

A. MERC calculated Total Current System Costs of $458,902,038, of which $340,561,226 or 74.2 percent is deemed to be the Minimum System. The remaining $118,340,813 or 25.8 percent of the Current System Costs represents the demand- or capacity-related cost of the system. The Minimum System cost was derived by multiplying average current unit cost of the minimum-sized pipe for plastic and steel, which is $8.16 and $25.31, respectively, by total quantity of plastic and steel installations, which is 17,395,594 and 7,847,381, respectively. The detailed results of MERC's minimum-size study that utilizes a 0.75-inch pipe can be found on page 2, Schedule 2.3 of Volume 3, Informational Requirement Document 12.

Q. DID MERC INCORPORATE THE RESULTS OF ITS 0.75-INCH MINIMUM-SIZE STUDY INTO ITS CCOSS?

A. No. For reasons discussed previously, MERC believes it is more appropriate to use the two-inch diameter pipe while performing a minimum-size study. The results of the 0.75-inch pipe diameter further confirm this conclusion.

Q. PLEASE EXPLAIN HOW THE RESULTS OF THE 0.75-INCH STUDY FURTHER CONFIRM MERC'S CONCLUSION THAT THE TWO-INCH STUDY IS MORE APPROPRIATE.

A. First, it is important to note that only 0.3 percent[25] of MERC's total distribution main currently in service is 0.75 inches in diameter. Utilizing a small sample of an entire population can lead to highly variable results that change significantly from one study to another (i.e., year to year). To illustrate, MERC compared the results had MERC utilized the 0.75-inch pipe diameter in its minimum-size study from its 2015 rate case[26] to the results of its 0.75-inch pipe diameter minimum-size study performed in this proceeding. The results of this comparison can be found in Table 1 below.

**Table 1**

| Description | Minimum System % from 0.75-inch Pipe Diameter | Minimum System % from 2-inch Pipe Diameter |
|---|---|---|
| Last Rate Case | 61.2% | 74.1% |
| Current Proceeding | 74.2% | 73.7% |
| Change | 13.0% | -0.4% |

Q. PLEASE EXPLAIN TABLE 1.

A. Table 1 demonstrates that the minimum system derived from a 0.75-inch pipe diameter would have produced a minimum system in this proceeding that was 13 percent larger than that from MERC's last rate case.[27] This compares to a 0.4 percent change from

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[25] Based on quantity, in feet, installed.

[26] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, INITIAL FILING, VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12, SCHEDULE 13 (Sept. 30, 2015).

[27] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, HOFFMAN MALUEG SURREBUTTAL at 19 (May 9, 2016).

MERC's last rate case[28] utilizing a two-inch pipe diameter. Absent large changes to either processes or plant additions and retirements, MERC views a 13 percent change in its minimum-size results, from one study to another, as being unacceptable. Therefore, MERC utilized the results of its two-inch pipe diameter study as the basis in its minimum-size method CCOSS.

Q. WHAT DOES MERC CONCLUDE REGARDING THE CCOSS THAT UTILIZES THE MINIMUM-SIZE STUDY?

A. A minimum-system study, whether a minimum-size or zero-intercept, is a theoretical analysis to determine what portion of distribution mains was built to simply attach a customer to the system, without any consideration of what that customer's load or demands may end up being. The end goal of the analysis is to determine what the smallest, minimum-sized or zero-sized distribution pipe would cost if the entire distribution system were to be replaced with that smallest, minimum-sized or zero-sized pipe. Because a minimum-sized (not zero-sized) pipe is chosen in a minimum-size study, theoretically there could still be a small amount of load, or "demand," that is being met by choosing that minimum size. Therefore, based on this theory, some analysts believe that a minimum-size study slightly over-assigns customer-related costs, when used in a CCOSS. MERC is unsure how to remedy this situation, nor is the Company aware of a method that would "adjust" the minimum-size study to accommodate for this. Therefore, MERC suggests more weight be placed on its zero-intercept CCOSS, presented in

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[28] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, HOFFMAN MALUEG SURREBUTTAL at 19 (May 9, 2016).

Section VI.C, and that the results of the minimum-size study be used to verify the results of the zero-intercept study.

## C. Zero-intercept Study

### *1. Overview*

Q. HAS THE COMMISSION REQUIRED MERC TO CONDUCT A ZERO-INTERCEPT STUDY AND PERFORM A CCOSS UTILIZING THE RESULTS OF THAT ZERO-INTERCEPT STUDY?

A. Yes. The Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736 required that MERC, in its next rate case, submit a zero-intercept CCOSS. Schedule 1.0 of Volume 3, Informational Requirement Document 12, provides the results of the CCOSS that utilizes the zero-intercept method to classify distribution mains.

Q. WHAT IS A ZERO-INTERCEPT STUDY?

A. A zero-intercept study "seeks to identify that portion of plant related to a hypothetical no-load, or zero-intercept, situation."[29] Recognizing that larger capacity pipes cost more to buy and install than smaller pipes, a zero-intercept study calculates (using OLS regression analysis) the relationship between pipe cost and pipe capacity. Based on this relationship, the study estimates the cost of installing a hypothetical pipe with zero capacity. Costs associated with building a distribution system with no capacity are

[29] NARUC, Electric Utility Cost Allocation Manual at 92 (1992).

regarded as customer costs. All additional costs of the distribution plant are presumed to be caused by the need to provide capacity and are therefore regarded as capacity costs.

Q. HOW IS A ZERO-INTERCEPT STUDY CALCULATED?

A. To conduct a zero-intercept study for gas distribution mains, one must: (1) determine, at a minimum, quantities installed, total investment cost, and average installed book cost of distribution mains, by asset attribute, such as material type and pipe size, and (2) determine the zero-intercept of distribution mains cost by performing a statistical analysis, specifically conducting a regression analysis and formulating a regression equation that relates pipe size and cost for each pipe of equal diameter.[30] Once a zero-intercept is determined, that zero-intercept value is multiplied by all quantities of distribution mains currently installed by the utility to arrive at a Total Minimum System Cost. Total Minimum System Cost divided by Total System Cost derives the portion of the system that is considered to be fixed investment, and is classified as customer related within a CCOSS. The remaining balance is considered costs in excess of the minimum system, and is classified as demand related within a COSS.[31]

Q. HOW DOES THE ACCURACY OF A ZERO-INTERCEPT STUDY COMPARE TO THE ACCURACY OF A MINIMUM-SIZE STUDY?

A. Generally, the zero-intercept study is perceived as being more accurate than a minimum-size study. As noted in Section VI.B, above, the goal of a minimum-system study –

[30] NARUC, Electric Utility Cost Allocation Manual, at 92-94 (1992).

[31] NARUC, Electric Utility Cost Allocation Manual at 92-94 (1992).

whether a minimum-size or zero-intercept – is to determine what the smallest, minimum-sized or zero-sized distribution pipe would cost if the entire distribution system were to be replaced with that smallest, minimum-sized or zero-sized pipe. Typically, the zero-intercept study is more accurate because it is theoretically calculating the cost of a zero-sized pipe, meaning it is a better reflection of fixed cost because a zero-sized pipe would theoretically not allow any load through it. Additionally, performing a zero-intercept study requires considerably more calculations at an intricate, statistical level than a minimum-size study, which requires simple mathematical averages and calculations. From this perspective, there is more involvement in conducting the zero-intercept study.

Q. WHAT TYPE OF REGRESSION MODEL DID MERC UTILIZE FOR ITS ZERO-INTERCEPT STUDY IN THIS RATE-CASE FILING?

A. Consistent with prior rate-case filings, MERC utilized an OLS regression model for its zero-intercept study in this rate-case filing.

Q. WHAT IS THE PURPOSE OF AN OLS REGRESSION?

A. OLS regression is a method used for estimating parameters within a regression analysis, with the goal of minimizing the differences between the actual observed data and the predicted responses to the calculated regression equation. OLS theory holds that the smaller this difference, the better fit of the model.

Q. WHAT ARE THE ASSUMPTIONS OF AN OLS REGRESSION?

A. There are four OLS regression assumptions that must be met in order for the calculated regression equation to provide the maximum likelihood estimator:

- Linearity and an additivity relationship between dependent and independent variables. The relationship has the following: (1) a straight line, (2) the slope does not depend on other variables, and (3) the effects of other variables are additive.
- There is statistical independence of the errors (i.e., there is a random sample).
- There is homoscedasticity (i.e., constant variance) of the sample errors when comparing against predicted values as well as when comparing against any independent variable.
- There is normality of the error distribution.

Q. DID MERC REVIEW EACH OLS REGRESSION IT PERFORMED FOR VIOLATIONS OF OLS ASSUMPTIONS?

A. Yes.

Q. WHAT STEPS DID MERC TAKE TO CHECK THE FIRST OLS ASSUMPTION, LINEARITY AND ADDITIVITY?

A. The first OLS assumption, linearity and additivity, can be identified by viewing a plot of the data. The plot should be representative of plotting either: (1) observed values versus predicted values, or (2) residuals versus predicted values. On an observed versus predicted plot, if the regression is satisfying this OLS assumption, the points on the plot will be symmetrically distributed around a diagonal line. On a residuals versus predicted plot, if the regression is satisfying this OLS assumption, the points on the plot will be symmetrically distributed around a horizontal line. MERC reviewed these plots when conducting its zero-intercept study. If the first OLS assumption appeared to be violated, changes were made as discussed in Section VI.C.2 below. Schedule 1.4 of Volume 3, Informational Requirement Document 12, provides the zero-intercept studies performed by MERC, along with various plots and key statistics.

Q. WHAT STEPS DID MERC TAKE TO CHECK THE SECOND OLS ASSUMPTION, STATISTICAL INDEPENDENCE OF ERRORS?

A. The second OLS assumption, statistical independence of errors, can be tested by viewing a plot of the data. The plot should be representative of plotting residuals versus independent variables. On these plots, if the regression is satisfying this OLS assumption, the points on each plot will be randomly and symmetrically distributed around zero. In addition to reviewing plots, a Durbin-Watson test can also be performed, though this test is generally performed while conducting a time series analysis as it tests for significant residual autocorrelation at lag one. The Durbin-Watson statistic will produce a value between zero and four. A value of two indicates there is no autocorrelation in the sample. Values approaching zero indicate positive autocorrelation and values approaching four indicate negative autocorrelation. When conducting its zero-intercept studies, MERC reviewed both the residuals versus independent variable plots and the Durbin-Watson statistic. If the second OLS assumption appeared to be violated, changes were made as discussed in Section VI.C.2 below. Schedule 1.4 of

Volume 3, Informational Requirement Document 12, provides the zero-intercept studies performed by MERC, along with various plots and key statistics.

Q. WHAT STEPS DID MERC TAKE TO CHECK THE THIRD OLS ASSUMPTION, HOMOSCEDASTICITY?

A. The third OLS assumption, homoscedasticity, can be identified by viewing a plot of the data. The plot should be representative of plotting either: (1) residuals versus predicted values, or (2) residuals versus independent variables. On either of these plots, if the points systematically get larger in one direction by a significant amount, that tends to signal a violation of this OLS assumption. In addition to reviewing plots, a test, like the White specification test, can be conducted to identify homoscedasticity. The null hypothesis for the White specification test is homoscedasticity, or that heteroscedasticity is not present. If a calculated p-value falls below a specified significance level (i.e., 0.05), then one must reject the null hypothesis and assume heteroscedasticity is present, a violation of the third assumption. When conducting its zero-intercept studies, MERC reviewed both the residuals versus predicted values and residuals versus independent variables plots and the White specification test while checking for homoscedasticity. If the third OLS assumption appeared to be violated, changes were made as discussed in Section VI.C.2. Schedule 1.4 of Volume 3, Informational Requirement Document 12, provides the zero-intercept studies performed by MERC, along with various plots and key statistics.

Q. WHAT STEPS DID MERC TAKE TO CHECK THE FOURTH OLS ASSUMPTION, NORMALITY OF THE ERROR DISTRIBUTION?

A. The fourth OLS assumption, normality of the error distribution, can be identified by viewing either a Normal Probability plot or a Normal Quantile plot of residuals. On either plot, if the regression is satisfying this OLS assumption, the data points will fall close to the diagonal reference line. If there is significant deviation from the line, this would indicate a violation of this OLS assumption. When conducting its zero-intercept study, MERC reviewed these plots. If the fourth OLS assumption appeared to be violated, changes were made as discussed in Section VI.C.2 below. Schedule 1.4 of Volume 3, Informational Requirement Document 12, provides the zero-intercept studies performed by MERC, along with various plots and key statistics.

Q. WHAT WERE THE KEY STATISTICS THAT MERC REVIEWED WHEN DETERMINING IF ITS REGRESSION RESULTS WERE ACCEPTABLE?

A. MERC reviewed the following key statistics: (1) R-squared; (2) F-value; (3) t-value; (4) Durbin Watson Statistic; and (5) White specification test p-value.

Q. WHY DID MERC CHOOSE THE R-SQUARED, F-VALUE, T-VALUE, DURBIN WATSON STATISTIC, AND THE WHITE SPECIFICATION TEST P-VALUE AS KEY STATISTICS?

A. R-squared is a measure of the goodness of fit of the regression equation. It is typically portrayed as a percentage, and measures the total variation in *y* explained by the combination of regressors. The higher the R-squared, the better fit of the model.

However, one should not solely rely on an R-squared value to determine if the regression equation is adequate; therefore, MERC also reviewed F-values and t-values. The F-value is another statistic that measures the fit of the regression equation. The calculated F-value must be larger than a deemed critical value (which was approximately around a value of 6 to 7 in MERC's regression analyses), therefore a high F-value is typically desired. The t-value is another statistic that makes inferences about the significance of the regression coefficients. The calculated t-value(s) must be larger than a deemed critical value (which was approximately around a value of 2 to 3 in MERC's regression analyses), therefore a high t-value is typically desired. The Durbin Watson and White specification tests were tests that MERC performed when assessing whether or not its zero-intercept studies may have violated various OLS assumptions.

Q. DID MERC PREPARE A ZERO-INTERCEPT STUDY UTILIZING DATA AT THE FINEST LEVEL POSSIBLE?

A. Yes. Section VI.C.2 below summarizes MERC's attempt to utilize data at the finest level possible in its zero-intercept study.

Q. DID MERC UTILIZE INSTALLED BOOK COST IN ITS ZERO-INTERCEPT STUDIES?

A. No. As stated in Section VI.A above, MERC utilizes the H-W Index to adjust historic book costs to current costs in its minimum-system studies.

### *2. Commission Requirements from MERC's Prior Rate Cases*

Q. HAS THE COMMISSION REQUIRED MERC TO TAKE CERTAIN MEASURES TO IMPROVE ITS ZERO-INTERCEPT STUDY IN THIS RATE-CASE FILING?

A. Yes. Order Point 32 in the Commission's October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617 required that MERC take the following actions in preparing future CCOSSs:

- Collect data on additional variables that impact the unit cost of mains installation;
- Avoid aggregating or averaging data and use data at the finest level reasonable;
- Check OLS regression assumptions and correct for violations; and
- Make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

Q. REGARDING THE FIRST REQUIREMENT, DID MERC COLLECT DATA ON ADDITIONAL VARIABLES THAT IMPACT THE UNIT COST OF MAINS INSTALLATION?

A. Yes. It is MERC's understanding that this requirement has been subsumed into Order Point 12 of the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736, that MERC collect project-specific data on installation footage, pipe diameter, and cost, and is addressed below in this testimony.

Q. REGARDING THE SECOND REQUIREMENT, DID MERC AVOID AGGREGATING OR AVERAGING DATA AND USE DATA AT THE FINEST LEVEL REASONABLE?

A. Yes. Later in this testimony, I discuss zero-intercept studies that MERC performed utilizing data at the finest level that avoids aggregating and/or averaging. Specifically, MERC attempted multiple studies utilizing (1) project-level data and (2) non-project-level data at the finest level available.

Q. REGARDING THE THIRD REQUIREMENT, DID MERC CHECK OLS REGRESSION ASSUMPTIONS AND CORRECT FOR VIOLATIONS?

A. Yes. As discussed earlier in this testimony, MERC reviewed various plots and test statistics after each regression performed to verify whether or not OLS assumptions were being violated. Later in this testimony, I discuss the methods MERC utilized to attempt to correct any violations of OLS assumptions. Additionally, Tables 1 and 2 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, indicate which OLS assumptions MERC believed were violated for each regression.

Q. REGARDING THE FOURTH REQUIREMENT, DID MERC MAKE ITS ZERO-INTERCEPT ANALYSIS MORE TRANSPARENT TO ENSURE THAT MERC'S WORK CAN BE EASILY REPLICATED?

A. Yes. MERC did the following to make its zero-intercept studies more transparent: (1) documented each regression and the associated test statistics and OLS violations in Tables 1 and 2 in Schedule 1.4 of Volume 3, Informational Requirement Document 12;

(2) provided detailed diagnostic reports and plots for each regression, found in Schedule 1.4 of Volume 3, Informational Requirement Document 12; (3) in this testimony, discuss what variables were removed and why; (4) in this testimony, discuss what steps were taken to correct for OLS assumption violations; and (5) in this testimony, discuss why MERC's recommended zero-intercept study is complete, makes sense intuitively, and satisfies each OLS assumption.

Q. WAS MERC ORDERED TO TAKE OTHER STEPS TO IMPROVE ITS ZERO-INTERCEPT STUDIES?

A. Yes. Order Point 12 in the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15-736 required that MERC, in its next rate case, take the following measures to further refine its zero-intercept analysis:

- Collect project-specific data on installation footage, pipe diameter, and cost;
- Research and, as soon as possible, begin collection of distribution-asset retirement at the same project-level detail; and
- Explore the use of this project-specific data in its zero-intercept CCOSS in future rate-case filings.

Q. WHERE DID THE PROJECT-LEVEL DATA REQUIREMENT COME FROM?

A. In MERC's 2013 rate case, the Minnesota Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") "argued that MERC should have built its model on project-level data rather than using data aggregated by pipe and year of installation. The OAG claimed that aggregating data in this way would obscure any relationships that might exist among variables at the project level…"[32] In response, MERC explained that it does not have adequate project-level data available and that such data was not necessary to a valid analysis. The ALJ and Commission rejected the OAG's argument. As the Commission noted, the ALJ concluded that:

> [N]either MERC nor other utilities in Minnesota have been required to maintain the types of historical data urged by the OAG for class cost of service studies. He further found that only one Minnesota utility maintains the type of data that the OAG regards as "project level" detail. The ALJ found that some of the data points that the OAG would include in the analysis—such as the length of the distribution main, or the reason why the pipe was installed—contribute little to the development of a "hypothetical zero-load or zero-sized distribution main on MERC's entire system."[33]

The Commission agreed:

> First, the Commission concurs with the ALJ's analysis finding MERC's zero-intercept study reasonable: MERC conducted its study based on data that was available, complete, and reflective of its current circumstances. Second, MERC's first two minimum-size studies confirmed the zero-intercept study's result. Specifically, they classified a slightly larger percentage of the mains account as customer costs, a result which is consistent with the tendency of a minimum-size study to designate more costs as customer costs.[34]

[32] *In the Matter of a Petition by Minn. Energy Res. Corp. for Auth. to Increase Nat. Gas Rates in Minn.*, Docket No. G011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (Oct. 28, 2014).

[33] *Id.*

[34] *Id.*

Consistent with this finding, the Commission required that in this subsequent rate case MERC must "avoid aggregating or averaging data and use data at the finest level reasonable."[35]

In MERC's last rate case, Docket No. G011/GR-15-736, the Department of Commerce, Division of Energy Resources ("Department") concluded that, while MERC had attempted to avoid aggregation of data to the extent possible, MERC should gather and use project-level data for its zero-intercept study in its next rate case. MERC disagreed with the Department's recommendation, stating that it was not able to gather sufficient project-level data for adequate use within a minimum-system study. During the evidentiary hearing in that case, MERC and the Department reached an agreement regarding the collection and future use of project-level data. In particular, MERC and the Department agreed that MERC would (1) collect project-specific data on installation footage, pipe diameter, and cost; (2) research, and as soon as possible, begin collection of

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[35] *Id.* at 46. In particular, the Commission concluded:

> While MERC's zero-intercept study is reasonable under the circumstances of this case, the OAG has highlighted several areas for potential improvement. The Commission will require MERC, in its next rate case, to take the following measures to improve its analysis:
>
> - collect data on additional variables that impact the unit cost of mains installation;
> - avoid aggregating or averaging data and use data at the finest level reasonable;
> - check ordinary-least-squares regression assumptions and correct for violations; and
> - make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

distribution asset retirement at this same project-level detail; and (3) explore the use of this project-specific data in its zero-intercept CCOSS in future rate case filings.

Q. WHAT DID THE COMMISSION CONCLUDE IN MERC'S LAST RATE CASE WITH RESPECT TO THE COLLECTION OF PROJECT-LEVEL DATA?

A. The Commission found that

> MERC's CCOSSs comply with the Commission's prior orders for refining MERC's methodology. While the OAG claimed that these studies suffered from methodological shortcomings, the Department evaluated these claims and found them to be unsubstantiated, or insufficient to indicate that the study's results would be biased. . . .
>
> That said, the Commission concurs with the Department's recommendation, and MERC's agreement, to further refine MERC's CCOSS.[36]

Q. WHAT DID THE DEPARTMENT CONCLUDE REGARDING MERC HAVING AN INADEQUATE AMOUNT OF PROJECT-LEVEL DATA FOR USE IN ITS ZERO-INTERCEPT CCOSS?

A. In MERC's last rate case, the Department concluded that

> [W]hile I agree that current data limitations may mean that using only project-level data would be limited in usefulness at this time, I stand by my recommendation that MERC use individual project data where possible. For example, MERC can explore use of project-level data for the period from 2006 to estimate the zero-intercept value for the system as a whole. It would not represent a significant burden for the Company to provide an additional zero-intercept model using project-level data from October 2006

[36] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 34 (Oct. 31, 2016).

forward in its next rate case. This analysis would demonstrate whether the Company has sufficient data going forward.[37]

Q. WHAT WERE MERC'S PROCEDURES IN ADDRESSING THE COMMISSION'S REQUIREMENTS FROM DOCKET NO. G011/GR-15-736 IN THIS RATE-CASE FILING?

A. MERC held multiple discussions internally, a teleconference call with an analyst from the Department on April 17, 2017, and an in person discussion with an analyst from the Department on August 3, 2017, to receive their input regarding MERC's plans to address the additional requirements. MERC's actions to address each of the requirements from the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order are addressed below.

Q. PLEASE SUMMARIZE MERC'S DISCUSSIONS WITH THE DEPARTMENT.

A. MERC organized a teleconference call with the Department on April 17, 2017, to present preliminary findings of available data for distribution assets and discuss options for addressing the Commission's requirements from MERC's last rate case. MERC mentioned it was able to obtain project-level data including installations and retirements starting in 2006, and presented to the Department a sample of Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12. MERC agreed it would perform an analysis for this rate-case filing utilizing the project-level data from Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12. Additionally, MERC agreed it would perform an analysis for this rate-case filing utilizing data that avoided averaging

[37] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, ZAJICEK SUR-SURREBUTTAL at 7 (May 20, 2016).

or aggregating (e.g., Taxing District). The data that avoided averaging or aggregating can be found in Table 1 of Volume 4, Nelson Workpapers. Regardless of the results from either analysis, the Department recommended that MERC discuss its process and the appropriateness of the data for facilitating CCOSS in future rate-case filings. On August 3, 2017, MERC discussed with the Department its preliminary findings and issues utilizing data at the finest level possible. The Department reiterated its recommendation from the April 17 discussion that MERC detail its processes and findings in testimony. Below are MERC's processes, findings, and conclusions regarding the utilization of data at the finest level possible in its zero-intercept study.

Q. REGARDING THE FIRST REQUIREMENT, DID MERC COLLECT PROJECT-SPECIFIC DATA ON INSTALLATION FOOTAGE, PIPE DIAMETER, AND COST?

A. Yes. Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, provides an example of what is currently available in MERC's Accounting System. Table 3 contains installation footage, pipe diameter, and cost by utility account (e.g., FERC Account 376), retirement unit (i.e., material and size), vintage (i.e., year), work order number (i.e., project) and FERC activity code (e.g., addition, retirement, etc.).

Q. REGARDING THE SECOND REQUIREMENT THAT MERC RESEARCH AND, AS SOON AS POSSIBLE, BEGIN COLLECTION OF DISTRIBUTION-ASSET RETIREMENT AT THE SAME PROJECT-LEVEL DETAIL, WHAT STEPS HAS MERC TAKEN TO ADDRESS THIS REQUIREMENT?

A. MERC researched what data are currently available with respect to project-level retirements. Based on this research, MERC determined that its existing processes do record and track retirement of assets; however, retirements are not recorded to the project (i.e., work order) in which the asset was originally installed. Rather, retirements are recorded to the project where the associated new installation is occurring. An example is detailed below.

Q. REGARDING THE THIRD REQUIREMENT THAT MERC EXPLORE THE USE OF THIS PROJECT-SPECIFIC DATA IN ITS ZERO-INTERCEPT CCOSS IN FUTURE RATE CASE FILINGS, WHAT STEPS DID MERC TAKE TO COMPLY WITH THIS REQUIREMENT?

A. MERC attempted to perform a zero-intercept study with the data from Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12. However, MERC has concerns with currently available project-level data that will make it unusable for CCOSS purposes in the future. These concerns are addressed below. The results of MERC's zero-intercept studies that utilize project level-data are presented in Table 2, Schedule 1.4 of Volume 3, Informational Requirement Document 12. MERC also evaluated what additional data would be required in order for project-specific data to be utilized to facilitate future CCOSSs.

Q. WHAT CONCERNS DOES MERC HAVE WITH THE USE OF CURRENTLY AVAILABLE PROJECT-LEVEL DISTRIBUTION ASSET DATA?

A. First, it must be noted that the currently available project-level data is only representative of MERC's distribution mains from October 2006 to present, which constitutes approximately 11 percent[38] of MERC's total distribution main currently in service. MERC has concerns with utilizing its currently available project-level data to facilitate CCOSS in the future because MERC's existing processes do not record retirement of assets to the project (i.e., work order) in which it was originally created. Rather, retirements are recorded to the project where the associated new installation is occurring. Take, for example, project 0013006297, from Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12. Project 0013006297 replaced 748 feet of two-inch steel pipe and 15 feet of two-inch plastic pipe with 775 feet of two-inch plastic pipe. Table 2, below, illustrates how this scenario is interpreted for purposes of a zero-intercept study utilizing this level of detail:

**Table 2**

| Project | Material | Size (inches) | Quantity (feet) | Book Cost | Unit Cost |
|---|---|---|---|---|---|
| 0013006297 | Plastic | 2 | 760 | $10,610.68 | $13.96 |
| 0013006297 | Steel | 2 | -748 | -$793.43 | -$1.06 |

Q. PLEASE EXPLAIN TABLE 2.

A. Table 2 illustrates the issues that exist if retirements of assets are not recorded against the original project in which they were installed. First, for reasons stated earlier, the steel retirement record is deemed invalid and would be excluded for zero-intercept purposes because it is negative. This is critical to note as the steel addition record in MERC's

[38] Based on quantity, in feet, installed.

Accounting System that is associated with the steel retirement record from project 0013006297 would still remain in the analysis, creating an inaccurate portrayal of MERC's distribution mains currently in service. This scenario occurs each time there is a retirement of a steel asset and an installation of a plastic asset in the same project (or vice-versa). Second, the plastic retirement record has skewed the plastic addition record as it was recorded against the current project (i.e., 0013006297) rather than the project in which it was originally installed (i.e., unknown). This simple example illustrates the complexity involved with attempting to record and track assets at a project level from installation through retirement.

Q. DID MERC ATTEMPT TO UTILIZE THE DATA FOR THE PERIOD FROM 2006 TO THE PRESENT TO ESTIMATE THE ZERO-INTERCEPT VALUE FOR THE SYSTEM AS A WHOLE?

A. Yes. MERC attempted to produce a zero-intercept study that satisfied all OLS assumptions utilizing gas distribution main data at a project level from 2006 to the present.

Q. HOW MANY OBSERVATIONS WERE INITIALLY INCLUDED IN MERC'S ZERO-INTERCEPT STUDY UTILIZING PROJECT-LEVEL DATA?

A. 10,127.

Q. DID MERC REMOVE ANY DATA PRIOR TO PERFORMING ITS REGRESSION ANALYSES?

A. Yes. First, MERC removed all retirement records for the reasons described previously. Specifically, retirement records are negative and therefore are invalid for zero-intercept purposes. Second, consistent with the method described in Section VI.A, above, MERC removed records that had a negative book cost. Additionally, MERC removed records that were non-unitized (i.e., did not have a material or size assigned) or had a quantity of zero.

Q. HOW MANY OBSERVATIONS WERE INCLUDED IN MERC'S ZERO-INTERCEPT STUDY UTILIZING DATA AT THE FINEST LEVEL POSSIBLE AFTER OBSERVATIONS WERE INITIALLY REMOVED?

A. 3,361.

Q. WHAT VARIABLES DID MERC INCORPORATE INTO ITS ZERO-INTERCEPT STUDY UTILIZING PROJECT-LEVEL DATA?

A. MERC utilized similar variables to those discussed in Section VI.A, above, while performing its zero-intercept studies at a project level. In particular, MERC obtained the following variables and related data from its Accounting System: (1) project number (i.e., work order); (2) pipe material; (3) pipe diameter; (4) quantity installed; (5) year of installation; (6) total book cost; and (7) total current cost. In addition, MERC calculated three additional variables for use in its zero-intercept study: (1) pipe diameter squared, by squaring the pipe diameter variable; (2) log current unit cost, by taking the log of current unit cost; and (3) square root of current unit cost, by taking the square root of current unit cost. Table 3 in Schedule 1.4 of Volume 3, Informational Requirement 12, includes the lowest level of data that MERC utilized in its project-level zero-intercept studies.

Q. HOW MANY ZERO-INTERCEPT STUDIES DID MERC ATTEMPT WHILE UTILIZING PROJECT-LEVEL DATA?

A. MERC attempted a total of 12 combinations of various zero-intercept studies, utilizing data at a project level, in its attempt to produce a result that satisfied all OLS assumptions, as defined in Section VI.C.1 above, and made sense intuitively.

Q. WAS MERC ABLE TO PRODUCE A ZERO-INTERCEPT STUDY WITH PROJECT-LEVEL DATA THAT DID NOT VIOLATE AT LEAST ONE OLS ASSUMPTION?

A. No. Table 2 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, presents a summary of the zero-intercept studies MERC performed, including their associated key statistics and an indication of which OLS assumptions MERC believes were violated, as defined in Section VI.C.1, above.

Q. WHAT STEPS DID MERC TAKE TO CORRECT FOR VIOLATIONS OF OLS ASSUMPTION?

A. MERC did the following while attempting to correct for OLS assumption violations:
(1) removed residuals deemed outliers or perceived as being too influential;
(2) transformed an independent variable (i.e., pipe diameter squared); (3) transformed the dependent variable (e.g., log of current unit cost or square root of current unit cost); and

(4) added a relative weight based on quantity (in feet) of gas mains installed (i.e., performed a Weighted Least Squares regression). Table 2 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, details the iteration of analyses MERC performed while attempting to correct for OLS assumption violations, utilizing data at a project level.

Q. WHAT METHOD(S) DID MERC USE TO IDENTIFY OUTLIERS OR INFLUENTIAL DATA POINTS IN ITS REGRESSION ANALYSES?

A. MERC reviewed residual plots when determining outliers. Studentized residuals outside a +/- 2 range are considered statistically significant at the 95 percent confidence level. Therefore, points that deviate substantially above 2 or below -2 are potential outliers.[39] MERC reviewed each regression equation carefully and excluded data points that had a studentized residual greater than 2.25 or less than -2.25. Graph three (moving left to right, top to bottom) in the diagnostics section of each regression summary, found in Schedule 1.4 of Volume 3, Informational Requirement Document 12, shows the plot of studentized residuals MERC reviewed while identifying outliers.

Q. WHAT STEPS DID MERC TAKE TO EVALUATE THE POSSIBILITY OF INCLUDING PROJECT-LEVEL DATA IN A FUTURE CCOSS?

A. MERC evaluated how its current data systems are set up and how project-level data and retirement information is tracked, and examined what modifications or upgrades would

[39] Christensen, R., Log-Linear Models and Logistic Regression (2d Ed. 1997).

be required in order to allow existing systems to track data in a way that would be usable in a CCOSS.

Q. HOW DOES MERC'S ACCOUNTING SYSTEM RECORD AND TRACK ITS GAS DISTRIBUTION MAIN ASSETS TODAY?

A. MERC's Accounting System maintains its gas main distribution assets by vintage (year), size (inches in diameter), and material (plastic, steel) which facilitates MERC's CCOSS. The assets are also recorded at a tax jurisdiction level to support property tax reporting requirements. This practice is known as mass asset accounting and is used where there are many similar type assets for a property account, such as gas mains. Mass property records are described as "[a]n account consisting of a large number of similar units for which the additions and retirements occur more or less continually and systematically over time. The life of any one unit is not dependent upon the life of any of the other units."[40]

Introducing a project dimension would be inconsistent with this practice as the life of any one unit would now be dependent on the life of another unit.

Q. PLEASE PROVIDE AN OVERVIEW OF MERC'S CURRENT PROCESSES FOR TRACKING ITS DISTRIBUTION ASSETS.

A. There are three main systems that interface with one another in order to properly record and track distribution assets: (1) Work Management; (2) Mapping or GIS; and (3)

[40] Edison Electric Institute/American Gas Association, Introduction to Depreciation for Public Utilities and Other Industries (2013).

Accounting System. The work management system is responsible for organizing and obtaining material and scheduling work based on a given work order's needs. Costs are accumulated in the Accounting System using the work order identifier to collect and report costs. Final quantities for installations and retirements are interfaced from the mapping system. While the three systems work in unison, each system does not retain information that it does not require for its designated task, e.g., the work management system does not obtain or retain actual costs. The systems also do not necessarily carry information into perpetuity, e.g., the mapping system uses the current work order number to interface installed and retired units that occurred as part of the effort but it does not retain this for future processing needs.

Q. ARE GAS DISTRIBUTION MAINS THE ONLY ASSET RECORDED IN MERC'S ACCOUNTING SYSTEM?

A. No. Various gas assets, such as meters, mains, services, etc., are recorded in MERC's Accounting System.

As mentioned earlier, MERC is *one* utility subsidiary of WEC Energy Group. As a result, the Accounting System is used not only by MERC but by all other utility subsidiaries to store and track various asset data. Therefore, the Accounting System is configured in a manner to leverage processes that are repeatable over all companies that use it. Making modifications to fit one company is both inefficient and costly, and the value of such modifications in terms of refining MERC's zero-intercept CCOSS is likely to be extremely limited or nonexistent. Based on initial analysis and review, it is not clear that project-level data would improve the accuracy of MERC's zero-intercept study.

Q. HAS MERC COMPLETED AN ANALYSIS OF THE COSTS ASSOCIATED WITH IMPLEMENTING A PROCESS FOR RECORDING RETIREMENTS OF DISTRIBUTION ASSETS AT THE SAME PROJECT IN WHICH THOSE ASSETS WERE ORIGINALLY CREATED?

A. No; however, MERC has determined that collecting data of all mains in a manner that would facilitate project-level zero-intercept studies, including both installations and retirements, would require expensive modification and/or creation of several company information systems, including but not limited to:

- Accounting system, to retain original project identifiers;
- Work Management System, to maintain detailed project level information while interfacing with the Accounting and Mapping System;
- CCOSS database, which would have to be designed and formatted by programming experts to query and export project level data out of the Accounting system and into SAS or another form of software capable of performing statistical analyses; and
- Hardware and/or servers to hold the extensive quantity of data.

In addition to company information systems, processes and employees would be impacted. Extensive testing and training would be required to facilitate such a large scale transition.

Q. IF MERC WERE TO RECORD RETIREMENTS OF DISTRIBUTION ASSETS AT THE SAME PROJECT IN WHICH THOSE ASSETS WERE ORIGINALLY CREATED, WOULD THE DATA BE USEFUL IN OTHER AREAS OF THE COMPANY'S OPERATIONS?

A. No. MERC would need to create a separate database solely for use in its CCOSS as this data would not be useful in other areas of MERC's operations.

Q. WHY SHOULD RETIREMENTS OF DISTRIBUTION ASSETS BE INCLUDED IN A ZERO-INTERCEPT STUDY?

A. Retirements represent the removal of an asset (i.e., taking the asset out of service). Conducting an analysis only on installations is problematic because it would lead to analyzing assets that are no longer in service. As discussed previously, one purpose of a minimum-system study is to determine what the smallest, minimum-sized or zero-sized distribution pipe would cost if the entire distribution system were to be replaced with that smallest, minimum-sized or zero-sized pipe. Retirements of distribution assets must be included in a minimum-system study in order to properly analyze distribution mains currently installed at a utility. Ignoring retirements would create an inaccurate portrayal of a utility's existing distribution system.

Q. WOULD RECORDING RETIREMENTS OF DISTRIBUTION ASSETS AT THE SAME PROJECT IN WHICH THOSE ASSETS WERE ORIGINALLY CREATED IMPROVE THE RESULTS OF MERC'S PROJECT-LEVEL ZERO-INTERCEPT STUDY?

A. No. MERC demonstrated it was unable to satisfy various OLS assumptions while utilizing project-level data. Including retirements in a minimum-system study is important from a conceptual basis, as discussed previously; however, the inclusion of retirements in the current project-level data would not correct OLS violations that MERC identified.

Q. WHY WOULD THE INCLUSION OF RETIREMENTS NOT IMPROVE MERC'S PROJECT-LEVEL ZERO-INTERCEPT STUDY IN THIS RATE-CASE FILING?

A. MERC's current project-level dataset is considered a sample of MERC's total distribution mains currently in service. As discussed previously, this sample represents roughly 11 percent[41] of MERC's distribution mains in service. In MERC's last rate case, Department Witness Mr. Michael Zajicek acknowledged that MERC's current data limitations may mean that using only project-level data would be limited in usefulness at this time, but suggested that MERC explore use of project-level data for the period for 2006 to estimate the zero-intercept value for the system as a whole.[42]

Additionally, since MERC is unable to classify distribution mains into projects prior to 2006, MERC finds the retirements in its project-level data to be irrelevant at this time because 97 percent[43] of the retirements have vintages prior to 2006. Since distribution mains remain in service for long periods of time, it will be many years until retirements

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[41] Based on quantity, in feet, installed.

[42] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, ZAJICEK SUR-SURREBUTTAL at 7 (May 20, 2016).

[43] Based on quantity, in feet, installed.

would impact a study, utilizing this level of data. For these reasons, MERC concludes its current project-level data is representative of analyses utilizing this data in the future.

Q. DID MERC REVIEW OTHER FACTORS REGARDING ITS PROJECT-LEVEL ZERO-INTERCEPT STUDIES?

A. Yes. MERC also reviewed the results to evaluate whether they made sense intuitively. For example, MERC compared each project-level zero-intercept study to the results of its minimum-size study. MERC found that each regression utilizing project-level data produced a minimum system with a greater percentage of costs attributable to the hypothetical no-load system compared to the results of MERC's minimum-size study. These results do not make sense intuitively. As discussed previously, because a minimum-size study derives a minimum-sized (not zero-sized) pipe, a minimum-size study will tend to slightly over-estimate the minimum system as compared to a zero-intercept study, not the other way around.

Q. WHAT DOES MERC CONCLUDE REGARDING PROJECT-LEVEL DATA FOR USE IN ITS ZERO-INTERCEPT STUDY?

A. MERC concludes: (1) while the Company does have project-level data going back to 2006, there are multiple problems with MERC's current-state project-level detail that will render it unusable for zero-intercept purposes into the future; notably, the fact that retirements are not tracked to the original project (as illustrated in Table 2 and the discussion above and Table 3 in Schedule 1.4 of Volume 3, Informational Requirement Document 12); (2) even though retirements are currently tracked in a manner that does not facilitate CCOSS at a project-level, MERC has demonstrated that its current data is sufficient for evaluating whether or not project-level data will improve its zero-intercept study; (3) the results of MERC's project-level zero-intercept studies do not satisfy OLS assumptions; and (4) the results of MERC's project-level zero-intercept studies do not produce results that make sense intuitively. MERC can continue to evaluate the appropriateness of incorporating project-level data into its zero-intercept studies in future rate-case filings; however, at this time, for reasons stated previously, MERC concludes that project-level data does not improve its zero-intercept study. Therefore, MERC recommends that the Commission not require MERC to implement costly system and process modifications in order to begin collecting and maintaining project-level data with retirements that could, theoretically, facilitate CCOSS in the future.

MERC also reviewed the Department's justifications for its recommendation that MERC begin collecting additional project-level data for potential use in future CCOSS in Docket No. G011/GR-15-736. In particular, the genesis of the Department's recommendation that MERC continue to collect and explore the possibility of utilizing project-level data was its conclusion that MERC's regression in that case violated the OLS assumptions. The Department concluded in Rebuttal Testimony that

> It appears that the Company's dataset is not sufficient to correct for these issues. . . . If individual project data is available, the Company should be required to use this data for its CCOSS in its next rate case. Additional data on a project level may allow for a better statistical model, better removal of outliers, and could correct for the issues inherent in the current zero-intercept method.[44]

[44] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, ZAJICEK REBUTTAL at 14 (Apr. 12, 2016).

In addition to exploring the potential use of project-level data, as required by the Commission's prior order, MERC has fully demonstrated that its recommended zero-intercept regression satisfies all of the OLS assumptions, as discussed in detail in Section IV.C.3. In light of the results of MERC's tests of its recommended zero-intercept regression, and the concerns discussed above regarding incorporation of project-level data, MERC recommends that the Commission find its recommended zero-intercept CCOSS to be a useful tool for purposes of setting rates in this proceeding.

Section IV.C.3 below illustrates how MERC's recommended zero-intercept study is complete and accurate.

Q. DID MERC ATTEMPT OTHER ZERO-INTERCEPT STUDIES UTILIZING UN-AVERAGED DATA?

A. Yes. Consistent with MERC's last rate-case filing, and Order Point 32.b in the Commission's October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617, MERC attempted to produce a zero-intercept study that satisfied all OLS assumptions while utilizing un-averaged non-project-level gas distribution main data at the finest level possible.

Q. WHAT VARIABLES DID MERC INCORPORATE INTO ITS ZERO-INTERCEPT STUDY UTILIZING UN-AVERAGED NON-PROJECT-LEVEL DATA?

A. MERC utilized the variables as discussed in Section VI.A, above, while performing its zero-intercept studies with un-averaged non-project-level data. In particular, MERC obtained the following variables and related data from its Accounting System: (1) pipe material; (2) pipe diameter; (3) taxing district; (4) quantity installed; (5) year of installation; (6) total book cost; and (7) total current cost. In addition, MERC calculated two additional variables for use in its zero-intercept study: (1) pipe diameter squared, by squaring the pipe diameter variable, and (2) log current unit cost, by taking the log of current unit cost. Table 1 in Volume 4, Nelson Workpapers, includes the lowest level of data that MERC utilized in its un-averaged non-project-level zero-intercept studies.

Q. HOW MANY OBSERVATIONS WERE INITIALLY INCLUDED IN MERC'S ZERO-INTERCEPT STUDY UTILIZING UN-AVERAGED NON-PROJECT-LEVEL DATA?

A. 5,720.

Q. DID MERC REMOVE ANY DATA PRIOR TO PERFORMING ITS REGRESSION ANALYSES?

A. Yes. Consistent with the method described in Section VI.A, above, MERC removed records that had a negative book cost. In addition, MERC also removed records that were non-unitized (i.e., did not have a material or size assigned) or had a quantity of zero.

Q. HOW MANY OBSERVATIONS WERE INCLUDED IN MERC'S ZERO-INTERCEPT STUDY UTILIZING UN-AVERAGED NON-PROJECT-LEVEL DATA AFTER OBSERVATIONS WERE INITIALLY REMOVED?

A. 5,649.

Q. HOW MANY ZERO-INTERCEPT STUDIES DID MERC ATTEMPT WHILE UTILIZING UN-AVERAGED NON-PROJECT-LEVEL DATA?

A. MERC attempted a total of 12 combinations of various zero-intercept studies, utilizing un-averaged non-project-level data, in its attempt to produce a result that satisfied all OLS assumptions, as defined in Section VI.C.1 above, and that made sense intuitively.

Q. WAS MERC ABLE TO PRODUCE A ZERO-INTERCEPT STUDY WITH UN-AVERAGED NON-PROJECT-LEVEL DATA THAT DID NOT VIOLATE AT LEAST ONE OLS ASSUMPTION?

A. No. Table 1 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, presents a summary of the zero-intercept studies MERC performed, including their associated key statistics and an indication of which OLS assumptions MERC believes were violated, as defined in section VI.C.1 above.

Q. WHAT STEPS DID MERC TAKE TO CORRECT FOR VIOLATIONS OF OLS ASSUMPTIONS?

A. MERC did the following while attempting to correct for OLS assumption violations: (1) removed residuals deemed outliers or perceived as being too influential; (2) added independent variables (e.g., taxing district); (3) transformed an independent variable (i.e., pipe diameter squared); (4) transformed the dependent variable (i.e., log of current unit cost); and (5) added a relative weight based on quantity (in feet) of gas mains installed (i.e., performed a Weighted Least Squares regression). Table 1, study one through twelve, in Schedule 1.4 of Volume 3, Informational Requirement Document 12, details the iteration of analyses MERC performed while attempting to correct for OLS assumption violations, utilizing un-averaged non-project-level data.

Q. WHAT METHOD(S) DID MERC USE TO IDENTIFY OUTLIERS OR INFLUENTIAL DATA POINTS IN ITS REGRESSION ANALYSES?

A. MERC used the same process as discussed earlier in Section VI.C.2 above while identifying outliers or influential data points. Specifically, MERC reviewed each regression carefully and excluded data points that had a studentized residual greater than 2.25 or less than -2.25.

Q. WHAT CONCLUSION DID MERC REACH REGARDING UTILIZING UN-AVERAGED NON-PROJECT-LEVEL DATA IN ITS ZERO-INTERCEPT STUDIES?

A. MERC concludes that utilizing data at the finest level possible does not produce satisfactory results, and impacts the ability to generate consistent results, or results that change gradually, through time. Table 1 in Schedule 1.4 of Volume 3, Informational Requirement Document 12, supports this conclusion. Included in Table 1 is the metric: number of observations removed (i.e., data points). Through an iterative process with each zero-intercept study, MERC reviewed the results and removed data points deemed as outliers or being perceived as too influential. On average, MERC completed nine of these iterations per zero-intercept study (studies 9 thru 12). Through this iterative process MERC removed, on average, more than 26 percent of the total observations. These removed observations accounted for roughly 67 percent of the total distribution system, in length, meaning that only 33 percent of the total distribution system remained in the study. Even after removing more than two-thirds of the gas distribution system from its analysis, MERC was still unable to satisfy all OLS assumptions, indicating this level of data does not produce satisfactory results. Therefore, MERC recommends the regression models created utilizing un-averaged non-project data at the finest level possible be given zero weight by the Commission for use in this and future rate-case filing's CCOSS.

Q. WHAT DOES MERC CONCLUDE REGARDING UTILIZING DATA AT THE FINEST LEVEL POSSIBLE WHILE CONDUCTING ZERO-INTERCEPT STUDIES?

A. MERC attempted multiple zero-intercept studies utilizing data at a project level but was unsuccessful in producing results that did not violate OLS assumptions and that made sense intuitively. Additionally, MERC attempted multiple zero-intercept studies utilizing un-averaged non-project-level data. This level of data also produced results that violated OLS assumptions and did not make sense intuitively. For these reasons, MERC concludes that utilizing data at the finest level possible will not improve its zero-intercept study. Later in this testimony, I discuss how MERC's recommended zero-intercept study satisfied OLS assumptions and yields results that make intuitive sense.

*3. MERC's Recommended Zero-intercept Study*

Q. DID MERC MAKE ANY MODIFICATIONS TO ITS PROCESS FOR CALCULATING ITS ZERO-INTERCEPT STUDY IN THIS RATE CASE?

A. Yes. Historically, MERC calculated its zero-intercept studies separately for plastic and steel mains. For this rate-case filing, MERC combined the two independent studies into one, adding Material Type as an independent variable to its zero-intercept study.

Q. WHAT FACTOR(S) DROVE MERC TO MAKE A CHANGE TO ITS PROCESS FOR CALCULATING ITS ZERO-INTERCEPT STUDY?

A. The process change was largely driven by efficiency and striving to increase transparency in its models. MERC performed 80 zero-intercept analyses while attempting to create a model that satisfied all OLS assumptions and made sense, intuitively. The 80 zero-intercept analyses MERC performed, and resulting summary statistics, can be found in Schedule 1.4 in Volume 3, Informational Requirement Document 12. Continuing MERC's process of independent studies for plastic and steel material would have forced MERC to review 160 analyses.[45] Combining MERC's independent analyses, leveraging core functionality of multiple regression, saved MERC a significant amount of time.

Q. WHAT REGRESSION MODEL DID MERC UTILIZE WHILE PERFORMING ITS ZERO-INTERCEPT STUDY FOR THIS RATE-CASE FILING'S CCOSS?

A. MERC's supported zero-intercept study is study #13 ("Zero-intercept Model #13") found in Schedule 1.4 of Volume 3, Informational Requirement Document 12. The resulting equation follows:

**Equation 1**

$$\textit{Average current unit cost} = a + b1 * (\textit{material type}) + b2 * (\textit{pipe diameter})^2$$

[45] 80 analyses multiplied by 2 (i.e., one study for plastic and one study for steel).

Q. PLEASE EXPLAIN EQUATION 1.

A. Equation 1 shows that Zero-intercept Model #13 assumes average current unit cost is a function of material type and pipe diameter squared. A relative weight was placed on quantity (in feet) installed.

Q. IS ZERO-INTERCEPT MODEL #13 THE BASIS FOR THE DEMAND- AND CUSTOMER-RELATED PORTION OF FERC ACCOUNT 376, GAS DISTRIBUTION MAINS, IN MERC'S CCOSS FOUND IN SCHEDULE 1.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. WHY DID MERC UTILIZE AVERAGE CURRENT COST AS THE DEPENDENT VARIABLE IN ITS REGRESSION EQUATION?

A. MERC performed 24 regression analyses utilizing data at the finest level possible while attempting to find the best fit model that satisfied all OLS assumptions, as discussed in Section VI.C.1 above. None of these analyses utilizing data at the finest level possible satisfied all OLS assumptions, nor did they make sense intuitively.

Both the NARUC Manual and the NARUC Gas Distribution Rate Design Manual (1989), as well as the Energy Regulators Regional Association's issue paper titled Cost Allocation & Methods for Distribution and Supply (2005), contend that a minimum-size study utilizes average unit cost data. As stated earlier, a minimum-size study and a zero-intercept study should have similar results. Therefore, it only makes sense that, if done properly, in order for a minimum-size study (which utilizes average costs) and a zero-intercept study to have comparable results, both must utilize average unit cost. Lastly, the NARUC Manual (pgs. 92-94) clearly states the data one would need to perform a zero-intercept analysis on various utility assets; each time it states that average costs should be utilized. MERC agrees with this statement and the results of its regression analyses confirm the use of average costs.

Q. HOW WAS AVERAGE CURRENT UNIT COST CALCULATED IN ZERO-INTERCEPT MODEL #13?

A. MERC utilized the same definition of average current unit cost in Zero-intercept Model #13 as discussed in Section VI.A above.

Q. DOES ZERO-INTERCEPT MODEL #13 SATISFY ALL OLS ASSUMPTIONS?

A. Yes. After reviewing the accompanying plots and data diagnostic reports, MERC concludes Zero-intercept Model #13 satisfies the four OLS assumptions, as defined in Section VI.C.1 above. Schedule 1.4 of Volume 3, Informational Requirement Document 12, shows the plots and summary statistics MERC reviewed in determining whether Zero-intercept Model #13 satisfied OLS assumptions or not, consistent with the approaches discussed in section VI.C.1 above. As the data and plots illustrate, Zero-intercept Model #13's data appear linear and have statistical independence of errors, homoscedasticity, and normality in the error distribution.

Q. HOW DID MERC CONCLUDE THAT ZERO-INTERCEPT MODEL #13 SATISFIED THE FIRST OLS ASSUMPTION, LINEARITY AND ADDITIVITY?

A. Plots displaying observed versus predicted values and residual versus predicted values were utilized to validate the first OLS assumption. If distinct patterns emerge, indicating the data is not symmetrically distributed around a line, there is a violation of the first OLS assumption. The first plot, observed versus predicted values, shows symmetrical and equal variance around a diagonal line, moving left to right. The second plot, residual versus predicted values, also shows symmetrical and equal variance around a horizontal line, moving left to right. Because the data points are roughly symmetrical around each line, MERC concludes Zero-intercept Model #13 satisfies the first OLS assumption.

Q. HOW DID MERC CONCLUDE THAT ZERO-INTERCEPT MODEL #13 SATISFIED THE SECOND OLS ASSUMPTION, STATISTICAL INDEPENDENCE OF THE ERRORS?

A. Plots displaying residual versus independent variables, and a Durbin-Watson test, were utilized to validate the second OLS assumption. Both the residual versus material and residual versus pipe diameter plots show symmetrical and equal variance around a horizontal line, moving left to right. The Durbin-Watson test for Zero-intercept Model #13 produced a value of 2.154. As mentioned previously, a Durbin-Watson value of two indicates there is no autocorrelation. Therefore, a value of 2.154 is well within an acceptable range. Additionally, a value of 2.154 leads us to not reject the test’s null hypothesis, indicating the errors are uncorrelated. Because both plots demonstrate symmetrical and equal variance around a horizontal line, and the Durbin-Watson test produced an acceptable value, MERC concludes Zero-intercept Model #13 satisfies the second OLS assumption.

Q. HOW DID MERC CONCLUDE THAT ZERO-INTERCEPT MODEL #13 SATISFIED THE THIRD OLS ASSUMPTION, HOMOSCEDASTICITY?

A. Plots displaying residual versus predicted variables or residuals versus independent variables, and the White specification test, were utilized to validate the third OLS assumption. The residual versus predicated plot was evaluated while reviewing the first OLS assumption, and the residuals versus independent variable plots were evaluated while reviewing the second OLS assumption. In both cases, MERC concluded these plots satisfied each OLS assumption. Given the same reasons in OLS assumption one and two, MERC concludes the third OLS assumption is satisfied through these plots. Additionally, MERC also reviewed the White specification test result. As mentioned previously, the null hypothesis for the White specification test is homoscedasticity, or that heteroscedasticity is not present. If a calculated p-value falls below a specified significance level (i.e., 0.05), then one must reject the null hypothesis and assume heteroscedasticity is present, a violation of the third assumption. The White specification test for Zero-intercept Model #13 produced a value of 0.0957. Therefore, the null hypothesis is not rejected. Because both plots demonstrate symmetrical and equal variance around a line, and the White specification test produced a value greater than 0.05, MERC concludes that Zero-intercept Model #13 satisfies the third OLS assumption.

Q. HOW DID MERC CONCLUDE THAT ZERO-INTERCEPT MODEL #13 SATISFIED THE FOURTH OLS ASSUMPTION, NORMALITY OF THE ERROR DISTRIBUTION?

A. A quantile plot of residuals was utilized to validate the fourth OLS assumption. The residuals in this plot all fall on, or near, the diagonal reference line, without significant deviation from the line. The plot does show a slight curvature of the data points towards the right side of the graph. As mentioned previously, significant deviation from the diagonal line indicates a violation of the fourth OLS assumption. MERC carefully reviewed the plot and concluded, given the conclusion regarding OLS assumption #2, that the slight curvature is not significant to warrant a violation of the fourth OLS assumption. Because there is not significant deviation from the diagonal line, MERC concludes Zero-intercept Model #13 satisfies the fourth OLS assumption.

Q. WHAT WERE THE RESULTS OF ZERO-INTERCEPT MODEL #13?

A. Zero-intercept Model #13 produced a fixed unit cost of $9.79 per foot. Utilizing $9.79 per foot translates to 55.1 percent of gas main costs attributed to a minimum system. The resulting 44.9 percent are attributed to the demand- or capacity-related cost of the system. The minimum system calculation for Zero-intercept Model #13 can be found on page 60 in Schedule 1.4 of Volume 3, Informational Requirement Document 12.

Q. HOW DOES ZERO-INTERCEPT MODEL #13 COMPARE TO MERC'S MINIMUM-SIZE STUDY?

A. Zero-intercept Model #13 fixed unit cost of $9.79 per foot compares to MERC's minimum-size study fixed unit cost of $13.40 (weighted average of its plastic and steel). Intuitively, these results make sense given minimum-size studies generally over-estimate the minimum system cost of mains as compared to zero-intercept studies, for the reasons described in Section VI.B, above.

Q. IS IT CORRECT TO ASSUME THAT THE UNIT COST OF A ZERO-SIZED PIPE DERIVED FROM A ZERO-INTERCEPT STUDY WILL BE LOWER THAN THE AVERAGE CURRENT COST OF A ONE-INCH PIPE DIAMETER OF THE SAME MATERIAL?

A. Not necessarily. It cannot be assumed that a zero-sized pipe will automatically be a lower cost than a one-inch pipe. This incorrect assumption can be further discredited by Schedule 2.3, shown in Volume 3, Informational Requirement 12. Schedule 2.3 illustrates that average current unit cost does not decrease in descending order by pipe diameter. While the general trend is that smaller pipe diameters cost less than larger pipe diameters, the observed data can deviate from that generalization, therefore the average current unit cost being calculated in a zero-intercept study for a zero-inch pipe diameter can potentially be higher than, for example, a one-inch pipe diameter. A regression analysis will take into consideration all observed data and provide the best fit linear line and best predicted estimation for a zero-sized pipe diameter; it will not force a zero-sized pipe diameter to be the lowest average unit cost, nor is that the purpose of utilizing a regression analysis when conducting the zero-intercept study.

Q. WHAT CONCLUSION DID MERC REACH REGARDING ZERO-INTERCEPT MODEL #13?

A. MERC concludes that Zero-intercept Model #13 is superior to its 24 other zero-intercept studies because it satisfied all OLS assumptions and produced results that intuitively make sense.

Q. HOW SHOULD THE COMMISSION REFLECT THE RESULTS OF THE CCOSS UTILIZING ZERO-INTERCEPT MODEL #13?

A. For the reasons stated above, and reasons discussed in Sections VI.D and VI.E below, MERC recommends that the Commission give the most weight to MERC's CCOSS that utilizes Zero-intercept Model #13 to classify FERC Account 376, gas distribution mains, for the purpose of setting rates in this proceeding.

**D. <u>Basic System Method</u>**

Q. WAS MERC ORDERED TO FILE A CCOSS UTILIZING A METHOD OTHER THAN THE MINIMUM-SYSTEM METHOD FOR PURPOSES OF CLASSIFYING FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. Yes. In MERC's last rate case, the Commission

> [D]eclined to adopt the OAG's recommendation to select multiple cost studies to guide the Commission's further analysis. While the Commission has sometimes found it necessary and appropriate to do so, in the current case the Commission is persuaded—as are MERC, the Department, and the Administrative Law Judge—that the Zero

> Intercept study is the best alternative in the record. Consequently the Commission finds no need to rely on other models as well.
>
> But the Commission's determination in this rate case pertains to *this case*. In MERC's next rate case the Commission will evaluate anew the parties' CCOSSs, and select one or more to guide the Commission's deliberation. To ensure that the Commission receives sufficient studies to evaluate at that time, the Commission will direct MERC to do the following in its next rate case:
>
> - File a Zero Intercept CCOSS and a Minimum Size CCOSS, as proposed by MERC;
> - File a Basic System CCOSS, and an Average and Excess CCOSS, as proposed by the OAG; and
> - Provide a substantive explanation and justification of its classification and allocation methods when it files its CCOSS.[46]

Q. WHAT IS THE BASIC SYSTEM METHOD AS RECOMMENDED BY THE OAG IN MERC'S LAST RATE CASE?

A. The Basic System method, as proposed by the OAG in Docket No. G011/GR-15-736, classifies distribution main investment and costs as 100 percent demand.[47] This is in contrast to a minimum-system study, which more accurately recognizes that a gas utility's distribution plant is designed both (1) to meet system capacity needs and (2) to connect customers regardless of their individual capacity needs.

[46] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 35 (Oct. 31, 2016).

[47] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, NELSON DIRECT at 7 (Mar. 18, 2016).

Q. WHAT LITERATURE WAS MERC ABLE TO FIND THAT SUPPORTED THE BASIC SYSTEM METHOD?

A. Very little. MERC found two sentences in the NARUC Gas Distribution Rate Design Manual that introduced the idea:

> The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function. Under this basic system theory, only those facilities, *such* as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system.[48]

Q. WAS MERC ABLE TO FIND OTHER LITERATURE THAT DISCUSSED THE BASIC SYSTEM METHOD?

A. No. However, the OAG presented sources in MERC's last rate case,[49] specifically published by the Regulatory Assistance Project, which referenced a Basic Customer method. These sources strictly discussed the classification method as it pertains to electric utilities.

Q. ARE THERE DIFFERENCES BETWEEN THE BASIC SYSTEM METHOD AND THE BASIC CUSTOMER METHOD?

A. The clearest definition MERC could find on the Basic Customer method concludes that "only customer-specific costs are treated as customer-related"[50]. Given this definition,

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[48] NARUC, Gas Distribution Rate Design Manual at 23 (1989) (emphasis added).

[49] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, NELSON DIRECT (Mar. 18, 2016).

[50] Jim Lazar, Smart Rate Design for a Smart Future, at A-4.

MERC believes the two methods can be interpreted differently from one another. Therefore, MERC did not rely on any of the literature that discussed the Basic Customer method for use in its Basic System CCOSS. Rather, MERC relied upon information that it was able to obtain regarding the Basic System method.

Q. WHAT DID THE COMMISSION CONCLUDE REGARDING THE BASIC SYSTEM METHOD IN MERC'S LAST RATE CASE?

A. In MERC's last rate case, the Commission declined to rely on the OAG's recommended Basic System CCOSS, finding that MERC's zero-intercept study was the best alternative in the record and therefore, the Commission did not need to rely on any other models. Nevertheless, the Commission indicated that in MERC's next rate case, it would evaluate anew the parties' CCOSSs and select one or more to guide the Commission's deliberation. To ensure that the Commission receives sufficient studies to evaluate at that time, the Commission directed MERC to file a Basic System CCOSS as proposed by the OAG, among other studies.

Q. HOW IS FERC ACCOUNT 376, GAS DISTRIBUTION MAINS, CLASSIFIED UTILIZING THE BASIC SYSTEM METHOD?

A. Because the cost of gas distribution mains does not vary *directly* with the number of customers on the system, for reasons discussed in Section VI.A, above, MERC classified FERC Account 376, gas distribution mains, as 100 percent demand related for its CCOSS that utilizes the Basic System method. Schedule 3.0 of Volume 3, Informational

Requirement Document 12, presents MERC's CCOSS results utilizing the Basic System method.

Q. DOES MERC AGREE WITH THE APPROACH OF CLASSIFYING THE COSTS OF GAS DISTRIBUTION MAINS AS 100 PERCENT DEMAND RELATED?

A. No. MERC does not agree with classifying the costs of gas distribution mains strictly as demand related. The Basic System approach to allocate gas distribution mains as 100 percent demand does not accurately reflect cost causation, does not consider utility-specific costs and investment, and is based on a flawed portrayal of a natural gas distribution system that assumes there is no delivery and service function of the natural gas system. MERC believes this method, as its name suggests, oversimplifies MERC's distribution system and fails to reflect the reality that MERC's gas distribution plant is designed both to (1) meet system capacity needs, and (2) connect customers regardless of their individual capacity needs.

As discussed in Section VI.A, above, there are two significant cost causation relationships for gas distribution mains: (1) the number of customers connected to the distribution system; and (2) the peak demands of those customers on the distribution system. "Fixed costs are usually assigned to the demand classification, except at the distribution level, where facilities are designed with the *number* and size of loads in mind."[51] Ignoring the customer portion of distribution mains creates an over-allocation

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[51] AGA, Gas Rate Fundamentals at 136 (1987) (emphasis added).

of costs to classes with small amounts of customers but large demand, and an under-allocation of costs to classes with large amounts of customers but little demand.

Q. DOES MERC HAVE ANY OTHER CONCERNS REGARDING THE BASIC SYSTEM METHOD?

A. Yes. As discussed previously, and also recommended by NARUC[52], not all costs can be readily classified to a single category. In these circumstances, a composite allocation factor is appropriate. MERC utilizes various composite allocators to classify a series of cost elements related to general assets that support MERC's distribution system. For example, intangibles, land and land rights, and structures and improvements because there is not a single cost causation relationship that can be attributed to these elements. Because these elements are in place to support MERC's distribution system, MERC concludes it is appropriate to classify them on the basis of its distribution plant composite allocator; however, because these elements cannot be traced back directly to individual customers, the Basic System method classifies these as demand-related cost elements. MERC disagrees that demand, itself, is accurate for these elements.

Q. WHAT DOES MERC CONCLUDE REGARDING THE USE OF THE BASIC SYSTEM METHOD TO CLASSIFY AND ALLOCATE FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. At the core, the Basic System method fails to accurately reflect cost causation, does not consider utility-specific costs and investment, and is based on a flawed portrayal of a

[52] NARUC, Gas Distribution Rate Design Manual at 32, 40 (1989).

natural gas distribution system that assumes there is no delivery and service function of the natural gas system. This oversimplification results in a misallocation of costs between customer classes. Specifically, customer-related costs incurred to connect customers to the distribution system are allocated to customers based on demand rather than number of customers. Misallocations result in inaccurate price signals, which can significantly impact the risk for potential customer bypass. For these reasons, MERC recommends no weight be placed on any CCOSS that incorporates the Basic System method when determining appropriate rate allocations in this proceeding.

**E. Average and Excess Method**

Q. WHAT DID THE COMMISSION ORDER WITH RESPECT TO MERC FILING A CCOSS USING THE A&E METHOD?

A. The Commission's Findings of Fact, Conclusions, and Order in the Company's last rate case required that MERC file an A&E CCOSS, as proposed by the OAG.

Q. HOW DID THE OAG PROPOSE THAT MERC CONDUCT AN A&E CCOSS IN MERC'S LAST RATE CASE?

A. As explained in the Surrebuttal Testimony of OAG witness Mr. Ron Nelson in Docket No. G011/GR-15-736, what the OAG described as the "average and excess CCOSS" is in fact the Basic System method with a weighted peak demand allocator applied. According to the OAG, "Under the Average and Excess method, I would classify the distribution system as 100 percent demand. Costs would then be allocated using commodity and demand allocators based on the system load factors."[53]

Q. HOW IS THE A&E METHOD DESCRIBED IN LITERATURE?

A. A&E, also called used and unused capacity, is an energy weighted method for allocating capacity costs to customer classes. It recognizes both the "average use of capacity and responsibility for the capacity required to meet the maximum system load"[54]. Average use represents the used capacity of the system, or minimum capacity needed to deliver total gas used. Excess use represents the unused capacity of the system and is defined as the difference between average use and peak capacity. This description is also consistent with the Commission's order in Docket No. G011/GR-15-736.[55]

Q. HAVE OTHER MINNESOTA UTILITIES BEEN REQUIRED TO FILE AN A&E CCOSS?

A. No. However, in CPE's 2015 rate case, Docket No. G008/GR-15-424, the Commission ordered CPE to file, in its next rate-case filing, a CCOSS that utilized the Peak and Average method.[56] Similarly, in Otter Tail Power Company's ("Otter Tail") last rate

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[53] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, NELSON SURREBUTTAL at 13 (.May 9, 2016).

[54] AGA, Gas Rate Fundamentals at 144 (1987).

[55] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 31 (Oct. 31, 2016).

[56] *In the Matter of an Application by CenterPoint Energy Res. Corp. d/b/a CenterPoint Energy Minn. Gas For Auth. to Increase Nat. Gas Rates in Minn.*, Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 54 (June 3, 2016).

case, Docket No. E017/GR-15-1033, the Commission ordered Otter Tail in its next rate case, to file a CCOSS using the Peak and Average method.[57]

Q. ARE THERE DIFFERENCES BETWEEN THE A&E AND PEAK AND AVERAGE METHOD?

A. Yes. The two methods utilize the same energy weighting (i.e., average demand); however, both incorporate different demand weights. The A&E method utilizes class non-coincident peak ("NCP")[58] and the Peak and Average method utilizes class contribution to coincident peak ("CP").[59]

Q. HOW DOES THE DIFFERENT DEMAND WEIGHTS USED BY THE A&E AND PEAK AND AVERAGE METHOD IMPACT COST ALLOCATION?

A. The theory is that at time of CP, the interruptible class would be called upon to shed its load, freeing up capacity to be used by the remaining customers connected to the distribution system. The interruptible class receives a discounted rate for taking on the risk of being interrupted at *any time* by order of MERC. Class NCP is the demand for each customer class at the point in time when each customer class reaches its individual peak demand. It does not take into consideration responding to interruptions ordered by MERC. If Class NCP is used improperly, a misallocation of costs to the interruptible class could result.

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[57] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 63 (May 1, 2017).

[58] NARUC, Electric Utility Cost Allocation Manual at 49 (1992).

[59] NARUC, Electric Utility Cost Allocation Manual at 57 (1992); NARUC, Gas Distribution Rate Design Manual at 27-28 (1989).

Q. IS A&E A COMMON METHOD FOR CLASSIFYING AND ALLOCATING DISTRIBUTION COSTS?

A. No. A&E is an allocator cost analysts can utilize for allocating production-related costs as there is evidence that energy loads are a determinant of production costs, specifically the sizing of a utility's generation assets.[60]

Q. WHAT DATA IS REQUIRED TO PERFORM AN A&E STUDY?

A. Three forms of data inputs are required to perform an accurate A&E study: (1) system CP demand; (2) NCP by customer class; and (3) average demand by customer class.[61]

Q. HOW IS SYSTEM CP DEMAND CALCULATED?

A. System CP demand is the capacity available on the distribution system to serve maximum load requirements when a utility's system as a whole is peaking. It is "usually expressed in terms of the peak hour or day"[62].

Q. HOW ARE CLASS NCP AND AVERAGE DEMAND BY CUSTOMER CLASS CALCULATED?

A. Class NCP demand is the maximum demand for each customer class at the point in time when each customer class reaches its individual peak demand, regardless of whether that

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[60] NARUC, Electric Utility Cost Allocation Manual, at 38 and 49 (1992).

[61] NARUC, Electric Utility Cost Allocation Manual at 49 (1992); AGA, Gas Rate Fundamentals at 146 (1987).

[62] AGA, Gas Rate Fundamentals at 144 (1987).

peak occurs when the system as a whole is peaking. Similar to peak capacity, it is usually expressed in terms of the peak hour or day. Average demand is the energy weight in the calculation of A&E, and is calculated by dividing annual throughput by 365 days.[63]

Q. DID MERC USE SYSTEM PEAK HOUR OR DAY IN ITS PEAK CAPACITY CALCULATION?

A. No. As discussed in MERC's 2015 rate case,[64] MERC utilized a *proxy* for peak capacity. MERC's proxy for peak capacity is based on each customer class's peak monthly usage for the given month where MERC's system realizes its peak.

Q. WHY DID MERC UTILIZE A PROXY FOR PEAK CAPACITY?

A. The primary driver is that MERC is unable to conduct an accurate daily or hourly forecast of NCP demand by customer class. As discussed in MERC's 2015 rate case, creation of a "true" Non Coincident Peak Demand by customer class would require that, at a minimum, daily load data be collected from a statistically significant sample, if not all customers within a customer class including Residential, SC&I, and LC&I general service classes. To do this, telemetry or smart meters would need to be installed for these customers so that daily load data could be collected and analyzed. At a minimum, an entire years' worth of data would be required, but the longer the collection of data, the more accurate a forecasted Non Coincident Peak Demand by customer class will be.

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[63] AGA, Gas Rate Fundamentals at 146 (1987).

[64] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, HOFFMAN MALUEG REBUTTAL at 34 (Apr. 12, 2016).

While MERC has not conducted an in-depth study on the precise costs, number of hours, or length of time that would be required to implement such a project, it can assuredly be stated that it would be a costly and time consuming venture. MERC does not believe this to be a sensible endeavor given that MERC has data available to compute a Non Coincident Peak Demand by customer class *proxy*. Absent the costly, time-consuming, and burdensome process required to compute a "true" Non Coincident Peak Demand by customer class, MERC views the Non Coincident Peak Demand by customer class proxy a suitable and useful representation.

Q. WHY IS MERC'S PROXY FOR NCP DEMAND SUFFICIENT?

A. A "true" Non Coincident Peak Demand by customer class takes all of the individual customers within a customer class, collects all of those customers' individual peak usage from throughout a year period, then sums all of those individual peaks to arrive at what is termed the Non Coincident Peak Demand for that customer class. Under the proxy method, MERC views an entire customer class's yearly usage, chooses the one month that has the highest usage from that year period, and that usage amount from that highest month is termed the Non Coincident Peak Demand by customer class proxy. Absent the costly, time-consuming, and burdensome process required to compute a "true" Non Coincident Peak Demand by customer class, MERC views the Non Coincident Peak Demand by customer class proxy a suitable and useful representation. It also bears noting that this proxy has been utilized in MERC's prior four rate-cases, including this one, for deriving its weighted peak demand allocators.

Q. HOW DID MERC APPLY THE A&E METHOD CONSISTENT WITH THE COMMISSION'S ORDER IN DOCKET NO. G011/GR-15-736?

A. Consistent with the Commission's Order, MERC utilized the A&E method "as proposed by the OAG." MERC relied upon the definition provided by OAG witness Mr. Nelson and the Commission's Findings of Fact, Conclusions, and Order, in MERC's 2015 rate case, which suggest this method classify FERC Account 376, gas distribution mains, as 100 percent demand related.[65] Schedule 4.0 of Volume 3, Informational Requirement Document 12, presents MERC's CCOSS results utilizing the A&E method.

Q. DOES MERC AGREE WITH THE APPROACH OF CLASSIFYING GAS DISTRIBUTION MAIN COSTS AS 100 PERCENT DEMAND RELATED?

A. No. MERC does not agree with classifying distribution main costs as 100 percent demand related, for the reasons stated in Section VI.D above.

Q. HOW IS FERC ACCOUNT 376, GAS DISTRIBUTION MAINS, ALLOCATED TO CUSTOMER CLASSES UTILIZING THE A&E METHOD?

A. In general, MERC allocated all capacity-related distribution costs to customer classes utilizing the A&E allocator. This allocator is partially weighted on the basis of average use, with the remainder being allocated on the basis of Class NCP.

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[65] *In the Matter of the Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G011/GR-15-736, NELSON SURREBUTTAL at 13 (May 9, 2016); FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 31 (Oct. 31, 2016).

Q. DOES MERC AGREE WITH THE APPROACH OF PARTIALLY ALLOCATING THE COSTS OF GAS DISTRIBUTION MAIN ON THE BASIS OF AVERAGE USE?

A. No. MERC does not find a cost causation relationship between the average quantities of gas consumed (energy) and gas distribution main costs. Energy costs are "largely made up of the commodity portion of purchased gas cost."[66] When gas distribution mains are installed, they are engineered to meet peak demand reliably and safely. A main will not be installed if it is incapable of serving peak demand. Therefore, it would be inappropriate to allocate gas main costs based on average demands. Further, if a gas utility were to size its main installations based on average use, it would be incapable of meeting peak demands.

Q. DOES MERC HAVE OTHER CONCERNS WITH PARTIALLY ALLOCATING THE COSTS OF GAS DISTRIBUTION MAINS ON THE BASIS OF AVERAGE USE?

A. Yes. MERC believes the energy component combined with class NCP creates a misallocation *between* its offerings of service. Specifically, this approach results in an over allocation of costs to MERC's interruptible classes as the energy and class NCP components, together, ignore MERC's existing interruptible tariff structure. This class of customers receives a discount for taking a risk of being subject to interruption at *any* time upon order from MERC. Neither component in the A&E allocation takes this tariff requirement into account, creating a misallocation of costs between classes. This particular misallocation of costs can be seen in column D of page 2, Schedule 4.2 in Volume 3, Informational Requirement Document 12. Take, for example, customer

[66] NARUC, Gas Distribution Rate Design Manual at 23 (1989).

classes NNG C&I Class 2 Firm and NNG C&I Class 2 – Interruptible. The volumetric rate that results for the firm service is lower than that of its counterpart interruptible service ($0.1118 and $0.1129, respectively). This intuitively makes no sense. As mentioned in Section IV.D, this misallocation of costs creates inaccurate price signals, increasing the risk for potential bypass. It is also important to note that the interruptible class is already a significant bypass risk as they are willing to be subject to interruptions in order to reduce their operating costs.

Q. WHAT DOES MERC CONCLUDE REGARDING THE USE OF THE A&E METHOD TO CLASSIFY AND ALLOCATE FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. For the reasons stated above, MERC believes the A&E method for allocating gas distribution mains is inappropriate for use in its CCOSS. As a result, MERC recommends the A&E method be given zero weight by the Commission for use in this rate case CCOSS. Additionally, because this methodology does not provide a reasonable or reliable data point for the Commission's consideration in setting rates, MERC requests that it not be required to file the results of such an A&E model in future rate case proceedings.

### F. <u>Conclusion for Distribution-Related Cost Classification</u>

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE CLASSIFICATION OF FERC ACCOUNT 376, GAS DISTRIBUTION MAINS?

A. MERC concludes that its supported zero-intercept study, Zero-intercept Model #13, most accurately allocates MERC's costs and should be given the most or sole weight for use in setting appropriate rate levels in this rate case. MERC has devoted significant resources in this case and prior cases to continue to evaluate and refine its zero-intercept study, providing further detail on the study and the validity of its regressions. Further, MERC's zero-intercept study results were corroborated by the results of its minimum-size study. While MERC agrees the minimum-size method over assigns customer-related costs to customer classes, the results of MERC's minimum-size study corroborate the results of the zero-intercept study. Additionally, the zero-intercept method alleviates the concern of the minimum-size study by deriving a true zero-load system.

The results of the A&E and Basic System methods should be given no weight in determining appropriate rates in this proceeding. The A&E method for allocating costs does not accurately reflect MERC's system and the drivers of system costs, and yields results that do not reasonably reflect the characteristics of MERC's rate offerings. Finally, the Basic System method should be given no weight as this approach fails to accurately reflect cost causation, does not consider utility-specific costs and investment, and is based on a flawed portrayal of a natural gas distribution system that assumes there is no delivery and service function of the natural gas system. MERC's zero-intercept method most accurately reflects MERC's system and the drivers of system costs, and is a more robust method overall compared to alternative methods.

### G. Allocation of Distribution Costs

Q. HOW DID MERC ALLOCATE DISTRIBUTION COSTS TO CUSTOMER CLASSES?

A. Distribution-related costs are allocated to customer classes utilizing either a customer allocator, demand allocator, or internally-derived plant allocator. Farm Tap classes are excluded from the allocation of costs in all distribution accounts except for FERC Accounts 301-303, Intangible Plant, 374, Land and Land Rights, and 375, Structures and Improvements. This is appropriate because all other distribution facilities currently do not serve MERC's Farm Tap customers. In addition, FERC Account 380, Services, is allocated to Farm Tap customers because MERC is currently seeking to replace customer-owned service lines with company-owned service lines in Docket No. G011/M-17-409.[67] This allocation method is appropriate as it will continue to provide stable price signals for these classes of customers.

Q. PLEASE EXPLAIN THE ALLOCATION METHODS USED TO ALLOCATE MERC'S DISTRIBUTION COSTS TO CUSTOMER CLASSES.

A. The following allocation methods were used to allocate distribution-related costs in MERC's CCOSS, found in Schedule 1.0 of Volume 3, Informational Requirement Document 12.

**FERC Accounts 301-303, Intangible Plant, 374, Land and Land Rights, and 375, Structures and Improvements**:

FERC Accounts 301-303, 374 and 375 were allocated to customer classes by MERC's internally-derived allocator, Distribution Plant. This allocator is derived from distribution plant investment in Accounts 376 through 385. It is appropriate that all customers receive an allocation of these costs because they are related to the general assets that support MERC's distribution system. Additionally, a composite allocation factor of distribution plant (excluding the items above) is

[67] *In the Matter of the Petition of Minn. Energy Res. Corp. for Approval of Farm Tap Customer-Owned Fuel Line Replacement Plan, Tariff Amendments, and Deferred Accounting,* Docket No. G-011/M-17-409.

appropriate in the situation where costs cannot be readily categorized to a single classification or a single customer parameter (e.g., usage).[68]

**FERC Account 376, Gas Distribution Mains:**

The customer-related portion of FERC Account 376 was allocated to customer classes by MERC's Customer allocator, excluding Farm Taps. As recommended by NARUC[69], the demand-related portion was allocated to customer classes by MERC's Weighted Peak Demand – Firm, excluding Farm Taps, and MERC's Weighted Peak Demand – Interrupt, excluding Farm Taps, allocators. These allocators are appropriate as a *portion* of costs are incurred to connect customers and a portion of costs are incurred by the size of facilities required to meet peak demands, as discussed in Section VI.A.

**FERC 378, Measuring & Regulating Equipment – General:**

FERC Account 378 was allocated to customer classes by MERC's Account 378 Demand, excluding Farm Taps allocator. This allocator consists of weighted peak demand for customer classes that are small to medium in size. This allocation method is appropriate because these costs are influenced by the sizing of facilities based on the non-coincident consumption of gas on the distribution facilities. It is appropriate to allocate these costs to the small and medium size classes because these customer classes are the only classes that utilize these assets, which consist

[68] NARUC, Gas Distribution Rate Design Manual at 32, 40 (1989).

[69] NARUC, Gas Distribution Rate Design Manual at 27 (1989).

mainly of regulating stations at the distribution system level. Costs directly related to the Minnesota Farm Tap Inspection Program were identified and carved out into FERC Account 378 (Direct Farm Tap). These directly assignable costs are allocated to customer classes by MERC's Account 378 Demand – Farm Tap allocator.

**FERC 379, Measuring & Regulating Equipment – Gate Station:**

FERC Account 379 was allocated to customer classes by MERC's Weighted Peak Demand, excluding Farm Taps allocator. This allocation method is appropriate because these costs are influenced by the sizing of facilities based on the non-coincident consumption of gas by all customer classes on the distribution system.

**FERC 380, Services:**

FERC Account 380 was allocated to customer classes by MERC's Services allocator. This allocator is a weighted customer allocator based on the Cost per Foot of Services, by rate class, taken from Company witness Ms. Amber Lee's Exhibit ___ (ASL-3) on service line projects from May 1, 2015, through April 30, 2017. In general, natural gas runs from the utility's distribution main to a single end-use customer, either a home or business, through a service line. Therefore, it is appropriate to use a Customer allocator while allocating Services-related costs to customer classes. The weighting by rate class is also appropriate as this more accurately allocates costs to customer class by taking into account that larger customer classes require larger diameter service lines. Furthermore, it is appropriate to allocate these costs to all customer classes because all customers require services in order to receive service from MERC.  The qualification of a Service falls under the FERC USOA definition of:

> This account shall include the cost installed of service pipes and accessories leading to the customers' premises.  A complete service begins with the connection on the main and extends to but does not include the connection with the customer's meter.

**FERC 381, Meters, and 382, Meter Connections & Installations:**

FERC Accounts 381 and 382 were allocated to customer classes by MERC's Meters allocator.  This allocator is a weighted Customer allocator based on the Cost per Meter by rate class from actual plant investment as of December 31, 2016.  It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system, and the complexity of the meter design and installation that is driven by the size of facilities required.  For example, larger customer classes require larger and more complex meter installations than smaller customer classes.  This allocation methodology is consistent with the recommendation from the AGA and NARUC.[70]  In the process of deriving this allocator, MERC identified and corrected an error that existed in its process utilized in prior years.  This error did not significantly impact the allocation results.  Rather, the error impacted the average cost per meter, similarly, for all classes.  Operation and maintenance ("O&M") costs associated with FERC Account 381, directly related to telemetry maintenance, were identified and allocated directly to those customer classes by

[70] AGA, Gas Rate Fundamentals at 142 (1987); NARUC, Gas Distribution Rate Design Manual at 24 (1989).

MERC's Customers – Telemeter allocator. It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system, and are directly related to customers classes with telemetry facilities installed.

**FERC Account 383, House Regulators:**

FERC Account 383 was allocated to customer classes by MERC's Customer – Small/Medium, excluding Farm Taps allocator. It is appropriate to use this allocation method because these costs vary based on the number of customers connected to the distribution system; however, Large and Super Large customer classes do not utilize house regulator facilities. Additionally, the AGA recommends House Regulators be allocated by a weighted customer allocator.[71]

**FERC Account 385, Industrial Metering & Regulating Station Equipment:**

FERC Account 385 was allocated to customer classes by MERC's Customers – Account 385, excluding Farm Taps allocator. It is appropriate to use this allocation method because these costs are incurred based on the number and size of industrial customers connected to the distribution system. Additionally, the AGA recommends Industrial Metering and Regulation Equipment be allocated by a special assignment allocator.[72]

[71] AGA, Gas Rate Fundamentals at 142 (1987).

[72] AGA, Gas Rate Fundamentals at 142 (1987).

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADDRESS REGARDING DISTRIBUTION-RELATED COST ALLOCATION?

A. Yes. MERC would like to address the volumetric rate calculated in the CCOSSs for interruptible class 2 through 4, shown in column D, page 2 of Schedules 1.2, 2.2, 3.2 and 4.2 of Volume 3, Informational Requirement Document 12.

Q. PLEASE SUMMARIZE THE RESULTS OF THE VOLUMETRIC RATE CALCULATED FOR INTERRUPTIBLE CLASSES 2 THROUGH 4 IN SCHEDULES 1.2, 2.2, 3.2 AND 4.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. MERC's CCOSSs produced a higher volumetric rate per therm for interruptible class 4 than class 3, and a higher volumetric rate per therm for class 3 than class 2. MERC reviewed its allocations and concluded these results are attributed to the allocated revenue and sales values from its customer re-class effort.

## VII. <u>CLASSIFICATION AND ALLOCATION OF CUSTOMER COSTS</u>

Q. HOW DID MERC CLASSIFY CUSTOMER COSTS?

A. Customer-related costs were classified to the customer classification category. The majority of customer costs were assigned to the customer sub-classification of customer; however, costs incurred directly related to serving transportation customers were classified to the enhanced other services sub-classification of customer to facilitate direct assignment to transportation customer classes.

Q. HOW DID MERC ALLOCATE CUSTOMER COSTS TO CUSTOMER CLASSES?

A. In general, customer costs are allocated to customer classes by MERC's Customer allocator because these costs vary with the number of customers connected to MERC's distribution system; however, costs that could be directly assigned to specific customer classes were directly assigned to those customer classes. This approach is consistent with the approach outlined in the NARUC Electric Utility Cost Allocation Manual.[73]

Q. WHAT CUSTOMER-RELATED COSTS WERE DIRECTLY ALLOCATED TO CUSTOMER CLASSES?

A. Costs incurred to serve transportation customers were identified and allocated directly to those customers by MERC's Transport Customer allocator. Costs directly related to residential or commercial and industrial customers in FERC Account 904, Uncollectibles Expense, were identified and allocated directly to those customers by MERC's Customers – Residential and Customers – C&I allocator. The ratio of residential to commercial and industrial customers was derived from the average historical Net Write-Offs from these customer classes for the calendar year ending December 31, 2016.

## VIII. ALLOCATION OF ADMINISTRATIVE AND GENERAL COSTS

Q. HOW DID MERC CLASSIFY ADMINISTRATIVE AND GENERAL COSTS?

A. The majority of MERC's administrative and general costs were classified to commodity, demand, and customer by MERC's internally-derived allocator, Total O&M. MERC's Total O&M allocator is derived from the summation, by classification, of Total O&M

[73] NARUC, Electric Utility Cost Allocation Manual at 22, 103 (1992).

costs (excluding administrative and general, direct assigned, and cost of gas related costs). This methodology is consistent with the approach outlined in the NARUC Electric Utility Cost Allocation Manual.[74] Costs incurred directly related to serving transportation customers were classified to the enhanced other services sub-classification of customer utilizing the proportional split of direct assigned O&M Customer Accounts Expense (Accounts 901-905) to Total O&M Expense.

Q. HOW DID MERC ALLOCATE ADMINISTRATIVE AND GENERAL COSTS TO CUSTOMER CLASSES?

A. Administrative and general costs were allocated to customer classes by either a sales allocator, demand allocator, customer allocator, or by direct assignment. Gas supply acquisition-related costs were allocated to customer classes by MERC's Sales allocator. Demand-related costs were allocated to customer classes by MERC's Peak Demand-Firm allocator and Weighted Peak Demand-Interrupt allocator. Customer-related costs, excluding direct assignment, were allocated to customer classes by MERC's Customers allocator. Costs incurred to serve transportation customers were allocated directly to those customers by MERC's Customers – Transport allocator.

[74] NARUC, Electric Utility Cost Allocation Manual at 22, 106 (1992).

## IX. ALLOCATION OF TAXES OTHER THAN INCOME TAXES

Q. HOW DID MERC ALLOCATE TAXES OTHER THAN INCOME TAXES TO CUSTOMER CLASSES?

A. Taxes other than Income Taxes ("TOTIT") associated with Real Estate & Property, Unauthorized Insurance Tax, Excise Tax and Use Tax, and Miscellaneous Revenues in Account 493 were allocated to customer classes by MERC's internally-derived Rate Base allocator. TOTIT associated with Unemployment Compensation, IBS Payroll Tax, and Retirement Benefits were allocated to customer classes by MERC's Salaries and Wages allocator.

## X. ALLOCATION OF INCOME TAXES

Q. HOW DID MERC ALLOCATE INCOME TAXES TO CUSTOMER CLASSES?

A. Income Taxes were allocated to customer classes based on MERC's internally-derived Rate Base allocator. A detailed discussion of this allocation method can be found in Schedule 1.8 of Volume 3, Informational Requirement Document 12.

## XI. ROCHESTER CAPACITY COST ALLOCATION

Q. WHAT INFORMATION DID THE COMMISSION ORDER MERC TO PROVIDE WITH RESPECT TO COST ALLOCATION METHODOLOGIES IN ITS ORDER APPROVING ROCHESTER PROJECT AND GRANTING RIDER RECOVERY WITH CONDITIONS IN DOCKET NO. G011/M-15-895?

A. The Commission's Order, at Order Point 8, required that in MERC's next general rate case, the Company provide "a discussion and analysis of its current interruptible and transportation rate structure, including cost-allocation methodologies, explaining the impact of excess Rochester capacity." I discuss MERC's cost allocation methodologies and the impact of the Rochester Project and Company witness Amber Lee discusses the current interruptible and transportation rate structure and proposed rate design changes regarding MERC's customer classes and rates.

Q. CAN YOU EXPLAIN THE CURRENT COST ALLOCATION METHODOLOGIES USED TO ALLOCATE COSTS TO MERC'S TRANSPORTATION AND INTERRUPTIBLE CUSTOMER CLASSES?

A. As discussed previously, MERC's CCOSS attempts to associate costs with customer classes based on cost causation. Transportation classes receive an allocation of most costs incurred by MERC as transportation classes utilize MERC's system similarly to non-transportation classes; however, transportation classes do not purchase gas or interstate pipeline transportation services from MERC. Therefore, transportation classes do not receive an allocation of commodity and sales-related production costs. Transportation classes do utilize MERC's assets related to the transmission and distribution of natural gas. Therefore, some of MERC's transmission and distribution-related costs are allocated to transportation classes. As discussed previously, transmission and distribution capacity-related costs are allocated to classes based on demand (i.e., non-coincident peak), and customer-related costs are allocated to classes based on the number of customers connected to the distribution system.

Cost allocations to the interruptible classes are similar to that of transportation classes. The largest exception is that interruptible sales classes receive an allocation of MERC's commodity and sales-related production costs. This allocation method is appropriate because interruptible sales classes do purchase their gas service from MERC. As for distribution-related costs, interruptible classes are subject to interruption by order from MERC at any time. While the theory behind interruptible load is that it can be curtailed during peak periods, MERC's distribution system is rarely constrained to the point where customers' loads are interrupted due to distribution system peak day constraints. Therefore, it is appropriate that interruptible classes receive an allocation of these costs, and that the interruptible class's entire peak demand be utilized in the allocation of these costs. NARUC concludes that this allocation method is appropriate.[75]

Q. WHAT IMPACT WILL MERC'S DISTRIBUTION SYSTEM UPGRADES RELATED TO THE ROCHESTER PROJECT HAVE ON COSTS AND THE ALLOCATION OF THOSE COSTS TO MERC'S CUSTOMER CLASSES?

A. The Rochester Project consists of upgrades to MERC's distribution system in Rochester, Minnesota. As a result, MERC's distribution-related costs will increase as the project progresses. Consistent with the allocation methodologies discussed previously, the added distribution-related costs will be allocated to all customer classes, whether firm, interruptible, or transportation, regardless of their geographic location. Specifically, capacity-related costs will be allocated to customer classes based on each class's individual maximum demand, and customer-related costs will be allocated to customer classes based on the number of customers within each customer class.

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[75] NARUC, Electric Utility Cost Allocation Manual at 75-76 (1992) ("Conversely, non-firm service may either be opportunity type sales without availability assurances, or sales from surplus capacity with limited assurances of availability. Thus, revenues derived from these sales, usually based on negotiated rates, may recover costs anywhere in the range of zero to the amount of the fully distributed costs.").

Q. DID MERC EVALUATE WHETHER ITS COST ALLOCATION METHODOLOGIES CONTINUE TO BE REASONABLE IN LIGHT OF THE ROCHESTER PROJECT?

A. Yes. MERC evaluated its cost allocation methodologies in light of the impacts that will result from the Rochester Project and concluded that MERC's methodologies continue to reasonably allocate costs to firm, interruptible, and transportation customers based on cost causation and accurately reflect appropriate pricing signals for customers regarding the cost and value of the service(s) they receive.

## XII. ROADMAP OF WORKPAPERS

Q. PLEASE DESCRIBE SCHEDULE 1.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.0 presents the summarized results of MERC's natural gas CCOSS, utilizing the zero-intercept method for classifying distribution mains, for the Minnesota service territory. Schedule 1.0 consists of 50 pages, and meets the requirements of: (1) the Commission's order in Docket No. G007,011/GR-10-977, 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, and (2) the Commission's Final Order in Docket No. G011/GR-15-736, requiring MERC submit a zero-intercept CCOSS in its next rate case.

Pages 1 through 4 summarize the various components of operating income, rate base, rate of return resulting from operations, and total revenue deficiency by customer class.

Pages 5 through 8 show the operating revenues by customer class based on the rates authorized in MERC's last general rate case proceeding in Docket No. G011/GR-15-736.

Pages 9 through 12 show the allocation of O&M expenses. Page 50 contains the detailed breakdown of the classification of O&M expenses that were utilized on pages 9 through 12.

Pages 13 through 16 show the allocation of depreciation expense, with general expense apportioned. Page 49 contains the detailed breakdown of the classification of depreciation expenses that were utilized on pages 13 through 16.

Pages 17 through 20 show the allocation of taxes other than income taxes.

Pages 21 through 24 show the allocation of other income and adjustments, both before and after income taxes. In the 2018 proposed test year, there are no other income and adjustments.

Pages 25 through 28 show the allocation of plant in service, with general expense apportioned. Page 45 contains the detailed breakdown of the classification of plant in service that was utilized on pages 25 through 28.

Pages 29 through 32 show the allocation of depreciation reserve, with general expense apportioned. Page 46 contains the detailed breakdown of the classification of depreciation reserve that was utilized on pages 29 through 32.

Pages 33 through 36 show the allocation of depreciation reserve (deferred taxes), with general expense apportioned. Page 47 contains the detailed breakdown of the classification of depreciation reserve (deferred taxes) that was utilized on pages 33 through 36.

Pages 37 through 40 show the allocation of construction work in progress, with general expense apportioned. Page 48 contains the detailed breakdown of the classification of construction work in progress that was utilized on pages 37 through 40.

Pages 41 through 44 show the allocation of other rate base components.

Q. PLEASE DESCRIBE SCHEDULE 1.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. Schedule 1.1 consists of 51 pages; one page of information for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 1.0, which utilizes the zero-intercept method for classifying distribution mains.

Q. PLEASE DESCRIBE SCHEDULE 1.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 1.0. Schedule 1.2 consists of 3 pages.

Page 1 of Schedule 1.2 is a summary of all the billing unit costs by customer class, broken down into the billing units of Per Meter Fixed Charge, Telemeter Maintenance 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 of Columns [B], [C] and [D] for each customer class. The column titled Total Therm Rate is the summation of Columns [F] and [G] for each customer class. Columns [I] and [J] portray the Daily Firm Capacity Rate on a per Daily Firm Capacity basis as it currently exists in MERC's tariffs, and on a per Therm basis, assuming 30 days in a month.

Page 2 of Schedule 1.2 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 values were taken from Informational Requirement Document 12, Schedule 1.3. Daily Firm Capacity values were taken from Company witness Amber Lee's Exhibit _____ (ASL-1), Schedule 2. Demand Costs, Daily Firm Capacity Costs, and Gas Supply Acquisition Costs were taken from the respective columns of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes.

Page 3 of Schedule 1.2 shows the creation of the Fixed Charge, Telemetering Maintenance Charge, and Enhanced Administrative Charge for each of the rate schedules. Meter Counts were taken from Informational Requirement Document 12, Schedule 1.3. Customer Costs were taken from the respective column of Informational Requirement Document 12, Schedule 1.1 on each of the respective pages for the customer classes. Telemetering Maintenance costs and Enhanced Administrative Costs were taken from the Enhanced Other Services column of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes. Telemetering Maintenance Costs were specifically taken from Column [G], line 10, and Enhanced Administrative Costs represent the remainder of the costs, excluding Telemetering Maintenance Costs, in the Enhanced Other Services column of Informational Requirement Document 12, Schedule 1.1, on each of the respective pages for the customer classes.

Q. PLEASE DESCRIBE SCHEDULE 1.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.3 presents a summary of the external allocation methodologies used within all of MERC's CCOSSs. Schedule 1.3 consists of 16 pages. A detailed discussion of each allocation method can be found in Schedule 1.6 of Volume 3, Informational Requirement Document 12.

Q. PLEASE DESCRIBE SCHEDULE 1.4 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.4 presents the detail of the zero-intercept studies performed by MERC. Schedule 1.4 consists of 283 pages.

Table 1 in Schedule 1.4 shows the summary statistics from MERC's zero-intercept studies utilizing data not at a project level. Study 1 through 12 attempt to utilize data at the finest level possible, a requirement by the Commission's October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617. Study 13 is the basis for the zero-intercept CCOSS, found in Schedule 1.0 of Volume 3, Informational Requirement Document 12.

Pages 8 through 59 contain the detailed diagnostic reports from each zero-intercept study found in Table 1 of Schedule 1.4.

Page 60 shows the derivation of the minimum-system and demand-related components from MERC's recommended zero-intercept study.

Table 2 in Schedule 1.4 shows the summary statistics from MERC's zero-intercept studies that utilized data at a project level. This table contains the information required by the Commission's October 31, 2016, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-15.736 that directed MERC, in preparation for its next CCOSS to: collect project-specific data on installation footage, pipe diameter, and cost; research and, as soon as possible, begin collecting data regarding the retirement of distribution assets at the same project-level detail; and in future rate cases, explore the use of this project-specific data in MERC's zero-intercept CCOSS.

Pages 64 through 111 contain the detailed diagnostic reports from each zero-intercept study found in Table 2 of Schedule 1.4.

Table 3 in Schedule 1.4 presents the project-level detail that MERC currently has available in its Accounting System. Table 3 is the basis for the zero-intercept studies found in Table 2 of Schedule 1.4.

Q. PLEASE DESCRIBE SCHEDULE 1.5 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.5 is an incremental cost analysis for MERC's Super Large Volume customers based on the CCOSS presented in Schedule 1.0. The result of the analysis is utilized by Company witness Ms. Amber Lee to demonstrate that the Super Large Volume customer classes are covering their incremental cost of service.

Q. PLEASE DESCRIBE SCHEDULE 1.6 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.6 identifies and describes each allocation method used in MERC's CCOSS.

Q. PLEASE DESCRIBE SCHEDULE 1.7 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.7 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 is calculated based on meter counts.

Q. PLEASE DESCRIBE SCHEDULE 1.8 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 1.8 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, and Order in Docket No. G007,011/GR-10-977, which adopts the ALJ's Proposed Order that income tax be allocated on the basis of taxable income by class that fully and only reflects the class cost of service study. The Commission affirmatively confirmed this allocation method for MERC in its October 28, 2014, Findings of Fact, Conclusions, and Order in Docket No. G011/GR-13-617.

Q. PLEASE DESCRIBE SCHEDULE 2.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 2.0 presents the summarized results of MERC's natural gas CCOSS, utilizing the minimum-size method for classifying distribution mains, for the Minnesota service territory.

Q. DOES SCHEDULE 2.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. IS THE CLASSIFICATION OF DISTRIBUTION MAINS THE ONLY DIFFERENCE BETWEEN SCHEDULE 2.0 AND 1.0, OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 2.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 2.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 2.0, which utilizes the minimum-size method for classifying distribution mains.

Q. DOES SCHEDULE 2.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 2.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 2.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 2.0.

Q. DOES SCHEDULE 2.2 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.2 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 2.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 2.3 contains the detail of the minimum-size study performed on MERC's distribution mains.

Q. PLEASE DESCRIBE SCHEDULE 2.4 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 2.4 is an incremental cost analysis for MERC's Super Large Volume customers based on the CCOSS presented in Schedule 2.0.

Q. PLEASE DESCRIBE SCHEDULE 3.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 3.0 presents the summarized results of MERC's natural gas CCOSS, utilizing the Basic System method for classifying distribution mains, for the Minnesota service territory.

Q. DOES SCHEDULE 3.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. IS THE CLASSIFICATION OF DISTRIBUTION MAINS THE ONLY DIFFERENCE BETWEEN SCHEDULE 3.0 AND 1.0, OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. No.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN SCHEDULE 3.0 AND SCHEDULE 1.0, OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 3.0 allocates only those distribution-related costs that vary directly with the number of customers by a customer allocator, as described previously. Distribution-related costs that do not vary directly with the number of customers are allocated by a demand allocator.

Q. PLEASE DESCRIBE SCHEDULE 3.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 3.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 3.0, which utilizes the Basic System method for classifying distribution mains.

Q. DOES SCHEDULE 3.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 3.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 3.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 3.0.

Q. DOES SCHEDULE 3.2 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.2 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 3.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 3.3 is an incremental cost analysis for MERC's Super Large Volume customers based on the CCOSS presented in Schedule 3.0.

Q. PLEASE DESCRIBE SCHEDULE 4.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 4.0 presents the summarized results of MERC's natural gas CCOSS, utilizing the A&E method for classifying distribution mains, for the Minnesota service territory.

Q. DOES SCHEDULE 4.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. IS THE CLASSIFICATION OF DISTRIBUTION MAINS THE ONLY DIFFERENCE BETWEEN SCHEDULE 4.0 AND 1.0, OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. No.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN SCHEDULE 4.0 AND SCHEDULE 1.0, OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 4.0 allocates all distribution-related capacity costs utilizing an A&E allocator rather than MERC’s weighted peak demand allocators.

Q. PLEASE DESCRIBE SCHEDULE 4.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 4.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 4.0, which utilizes the A&E method for classifying distribution mains.

Q. DOES SCHEDULE 4.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 4.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 4.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 4.0.

Q. PLEASE DESCRIBE SCHEDULE 4.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 4.3 is an incremental cost analysis for MERC’s Super Large Volume customers based on the CCOSS presented in Schedule 4.0.

Q. PLEASE DESCRIBE SCHEDULE 5.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5.0 presents the summarized results of MERC’s natural gas CCOSS, utilizing the zero-intercept method for classifying distribution mains, for the Minnesota service territory.

Q. DOES SCHEDULE 5.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.0 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. WHAT DIFFERENCES EXIST BETWEEN SCHEDULE 5.0 AND SCHEDULE 1.0, OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Schedule 5.0 utilizes MERC's current customer classes; Schedule 1.0 utilizes MERC's proposed customer classes.

Q. PLEASE DESCRIBE SCHEDULE 5.1 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5.1 presents a functionalized and classified revenue requirement and rate base allocation for each customer class. The information in this schedule is derived from the CCOSS presented in Informational Requirement Document 12, Schedule 5.0, which utilizes the zero-intercept method for classifying distribution mains.

Q. DOES SCHEDULE 5.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12 FOLLOW THE SAME LAYOUT AS PRESENTED IN SCHEDULE 1.1 OF INFORMATIONAL REQUIREMENT DOCUMENT 12?

A. Yes.

Q. PLEASE DESCRIBE SCHEDULE 5.2 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5.2 presents a summary of the CCOSS by billing unit for each customer class, based on the CCOSS presented in Schedule 5.0.

Q. PLEASE DESCRIBE SCHEDULE 5.3 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5.3 summarizes the external allocation methodologies used in MERC's natural gas CCOSS presented in Schedule 5.0.

Q. PLEASE DESCRIBE SCHEDULE 5.4 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 5.4 is an incremental cost analysis for MERC's Super Large Volume customers based on the CCOSS presented in Schedule 5.0.

Q. PLEASE DESCRIBE SCHEDULE 6.0 OF VOLUME 3, INFORMATIONAL REQUIREMENT DOCUMENT 12.

A. Schedule 6.0 presents the summarized results for each of MERC's natural gas CCOSSs, for the Minnesota service territory.

## XIII. CONCLUSION

Q. IN YOUR OPINION, DOES MERC'S ZERO-INTERCEPT CCOSS PROVIDE A REASONABLE BASIS FOR ESTABLISHING RATES IN THIS CASE?

A. Yes. MERC's zero-intercept CCOSS provides reasonable estimates of revenue requirements by customer class, based on sound cost causation principles, and supports the rates requested in this case.

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

A. Yes.