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March 22, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing MI 48917

Re: Michigan Gas Utilities Corporation
Case No. U-20718

Dear Ms. Felice:

Enclosed for electronic filing in the above matter are:

- (1) Application;
- (2) Notice of Hearing;
- (3) Certification of Richard F Stasik;
- (4) Index of Exhibits;
- (5) Direct Testimony, non-confidential Exhibits of Theodore T. Eidukas, Joseph L. Zgonc, Jared J. Peccarelli, Ann E. Bulkley, Aaron L. Nelson, Nathan W. Lee, and Shannon L. Burzycki;
- (6) Non-confidential documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission's order dated July 31, 2017, issued in Case No. U-18238;
- (7) Protective Order;
- (8) Appearances of Sherri A. Wellman, Paul M. Collins, and Michael B. Fisher; and
- (9) Proof of Service reflecting electronic service on intervenors in Case No. U-17880.

Hard-copies containing the non-confidential version of this filing, as well as a USB of the workpapers in native electronic format and documentation addressing Part III of the Rate Case Filing Requirements in Case No. U-18238 will be directly served on the Commission Staff and all intervening parties in Case No. U-17880, the Company's last general rate case.

MILLER, CANFIELD, PADDOCK AND STONE, P.L.C.

Ms. Lisa Felice

-2-

March 22, 2021

If you have any questions, please call me at the number above.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

Sherri Wellman

By: _____

Sherri A. Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email =
wellmans@millercanfield.com C = AD O =
Miller Canfield
Date: 2021.03.22 12:38:47 -04'00'

SAW/ehk
Enclosures

cc w/enc: Lori Mayabb, MPSC (MayabbL@michigan.gov)
Richard Stasik (Richard.Stasik@wecenergygroup.com)
Koby Bailey (Koby.Bailey@wecenergygroup.com)
Theodore Eidukas (Theodore.Eidukas@wecenergygroup.com)

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)

Case No. U-20718

APPLICATION

MICHIGAN GAS UTILITIES CORPORATION (“MGUC” or the “Company”) hereby requests authority from the Michigan Public Service Commission (“MPSC” or the “Commission”) to, among other things, (i) increase rates for the sale, distribution and transportation of retail natural gas rates, (ii) redesign rates, (iii) implement a main/pipeline replacement rider, and (iv) make miscellaneous tariff changes. In support of these requests, MGUC respectfully represents as follows:

I. INTRODUCTION

1. MGUC is a public utility engaged in the purchase, storage, transportation, distribution and sale of natural gas to approximately 180,000 customers in the Southern and Western portions of Michigan’s Lower Peninsula.

2. MGUC is a corporation organized under the laws of the state of Delaware, with its principal office located at 899 S. Telegraph Road, Monroe, Michigan 48161, and is authorized to transact business in the state of Michigan. MGUC is a subsidiary of WEC Energy Group Inc.

3. MGUC’s retail natural gas business is subject to the jurisdiction of the Commission pursuant to 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq. Pursuant to these statutory provisions, the Commission has jurisdiction to regulate the Company’s retail natural gas sales, transportation, and

distribution rates to provide the Company with a fair opportunity to recover the costs of providing service to its customers.

4. MGUC's last general base rate case was Case No. U-17880. That case was concluded by a Commission Order Approving Settlement Agreement dated December 11, 2015. The revised base rates established in that case were established based on a 2016 test year, and an authorized rate of return on common equity of 9.90%.

5. On February 3, 2020, MGUC filed its rate Filing Announcement in Case No. U-20718 pursuant to the rate case filing requirements established by the Commission's July 31, 2017 Order in Case No. U-18238, and on February 5, 2020, MGUC filed its amended Filing Announcement. Thereafter, as a result of the unprecedented COVID-19 pandemic and the resulting disruption of businesses and significant increases of unemployment, MGUC agreed to Staff's request to delay its rate case filing. Subsequently, on May 14, 2020, MUGC filed its application in Case No. U-20797 for temporary relief in the form of deferred accounting. In that filing MGUC advised that it eventually would be filing its case in U-20718 and sought to waive the need for MGUC to re-satisfy the 30-day filing announcement requirement of MCL 460.6a(1). On July 23, 2020, the Commission issued its order in Case No. U-20797 granting MGUC (i) deferred accounting approval from January 1, 2021 through December 31, 2021, or until new base rates are authorized in Case No. U-20718, and (ii) a waiver regarding the filing announcement in Case No. U-20718.

6. This Application is accompanied and supported by the written testimony, exhibits and workpapers of seven witnesses. The Company's presentation in this case was prepared in accordance with the Rate Case Filing Requirements established by the Commission in Case No. U-18238.

II. REQUESTED BASE RATE INCREASE

7. Based on 2022 projected costs of providing service to the Company's customers, and due, in large part, to substantial infrastructure investments, the Company's existing retail base rates for natural gas services will be unreasonably low and inadequate.

8. Additionally, this rate filing presents data for a historical year ended December 31, 2019, as required by the Commission Order in Case No. U-18238. MGUC proposes that rates be established based upon a projected test year ending December 31, 2022. The use of this projected test year data allows the revised base rates established in this case to more closely reflect the conditions that will likely exist at and after the time the revised base rates set by the final order in this case are placed in effect.

9. Several factors have, and are expected to continue to have, a significant impact on the Company's costs of providing service to its customers, rendering existing base rates unreasonably low, inadequate and precluding the Company from earning a reasonable return on its investments to provide service to customers. Importantly, MGUC's existing base rates do not reflect significant investments in capital infrastructure made by the Company since its last rate case in U-17880 to address the safety and reliability of gas service to its customers. Additionally, MGUC's existing base rates do not reflect the reduction to operations and maintenance ("O&M") expenses, despite recent inflation, compared to MGUC's last rate case. This reduction in O&M expenses is the result of MGUC's cost management since its parent company, Integrys, Inc., was acquired by the WEC Energy Group in June 29, 2015. These factors, as described in more detail in the supporting testimony and exhibits, necessitate an increase in MGUC's current retail natural gas rates.

10. Because the alternative relief granted by the Commission in Case No. U-20797 only lasts through 2021, the Company will experience a revenue deficiency of \$15,127,536 in 2022. This 2022 test year revenue deficiency represents the results of a complete examination of the relevant items of investment, expenses, and revenues for the determination of just and reasonable retail natural gas rates for MGUC's customers.

11. MGUC proposes that retail natural gas rates be established to reflect an overall rate of return on total rate base of 5.72% and a rate of return on common equity of 10.20%. The capital structure ratios used are based upon the Company's actual capital structure as of December 31, 2019.

12. MGUC represents that, without taking into account the rate design changes proposed by the Company, the proposed revenue increase of not less than \$15,127,536 annually is required in order for the Company to maintain an adequate, reliable and safe natural gas transportation and distribution system and to allow MGUC a reasonable opportunity to earn the return to which the Company is entitled by law.

III. RATE DESIGN, TARIFF AND OTHER RATE-RELATED PROPOSALS

13. MGUC's proposed rates for each customer class rate schedule are shown on Schedule F2 of Exhibit A-16. These rates are designed to recover the projected revenue deficiency. MGUC requests Commission approval of the proposed rates.

14. The Company is also proposing that the Commission authorize MGUC to implement a main/pipeline replacement rider. In view of the Company's (i) relatively small size, (ii) its substantial capital spending, and (iii) the non-revenue producing nature of these necessary capital projects, it is appropriate to authorize MGUC to collect the capital-related costs before they are placed in rate base.

15. In addition, MGUC is seeking miscellaneous revisions to the terms and conditions of its tariffs.

16. MGUC proposes to implement its revised rates no earlier than January 1, 2022, and no later than the day after the Commission issues an order approving MGUC's request.

IV. TESTIMONY AND EXHIBITS

17. MGUC is filing herewith written testimony, exhibits and workpapers in support of the requested rate increase and related approvals requested herein. The positions and relief described in the direct testimony and exhibits should be considered as if specifically requested in this Application. MGUC is also filing a proposed Protective Order to govern the release, use and disclosure of certain testimony, workpapers and responses in Part III that contain confidential information, or in future responses to discovery.

V. REQUEST OF RELIEF

18. Because the alternative relief granted by the Commission in Case No. U-20797 only lasts through 2021, MGUC's current natural gas rates, based on the projected 2022 test year, will be unjust and unreasonable. Such rates are insufficient to permit the Company to recover the costs of providing service to its customers, including a reasonable return on investments to provide such service, to which MGUC is entitled by law. MGUC's retail natural gas rates are expected to be so low as to deprive it of a reasonable return on investments to provide such service to which MGUC is entitled by law. MGUC's retail natural gas rates are expected to be so low as to deprive it of a reasonable return on its property and will amount to confiscation of the Company's property contrary to MGUC's rights under the Constitution of the United States and the Constitution and laws of the State of Michigan. The inadequacy of these rates reduce the Company's revenues and

overall rate of return below a proper and reasonable level, and it is unjust and unreasonable to require MGUC to render natural gas service to its customers at such rates.

WHEREFORE, Michigan Gas Utilities Corporation requests the Commission to:

- A. Issue and publish its notice of hearing setting an early hearing date;
- B. Find and determine as based on the Company's direct case that for service rendered beginning January 1, 2022, existing rates and charges are unreasonably low and inadequate and should be increased to protect the constitutional right of the Company to earn a reasonable and non-confiscatory return;
- C. Authorize the Company to adjust its existing rates and charges so as to produce additional revenue of not less than \$15,127,536 annually;
- D. Approve changes in charges and terms and conditions of service as addressed in the supporting testimony and exhibits;
- E. Authorize all other changes and suggestions made and supported in the Company's testimony and exhibits, including approving the main replacement rider; and
- F. Grant such other and further relief as may be lawful and proper.

Respectfully submitted,

MICHIGAN GAS UTILITIES CORPORATION

Sherri Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email =
wellmans@mlcmlc.com C = AD O = Miller Canfield
Date: 2021.03.22 12:39:36 -0400

Dated: March 22, 2021

By:

One of its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
Michael B. Fisher (P84781)
Attorneys for Michigan Gas Utilities Corporation
Miller, Canfield, Paddock and Stone, P.L.C.
One Michigan Avenue, Suite 900
Lansing, MI 48933
(517) 487-2070

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

**NOTICE OF HEARING
FOR THE NATURAL GAS
CUSTOMERS OF
MICHIGAN GAS UTILITIES CORPORATION
CASE NO. U-20718**

- Michigan Gas Utilities Corporation requests Michigan Public Service Commission approval to increase its retail rates for the sale, distribution, and transportation of natural gas and for other relief.
- The information below describes how a person may participate in this case.
- You may call or write, Michigan Gas Utilities Corporation, 899 S. Telegraph Rd, Monroe, MI 48161, (734) 457-6120 for a free copy of its application. Any person may review the application at the offices of Michigan Gas Utilities Corporation.
- The prehearing conference in this matter will be held:

DATE/TIME: _____, _____, 2021, at _____ a.m.

BEFORE: Administrative Law Judge _____

LOCATION: **Video/Teleconferencing**

PARTICIPATION: Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8090, or by email at mpscdockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Michigan Gas Utilities Corporation's (MGUC) March 22, 2021 application for approval to increase its rates for the sale, distribution, and transportation of natural gas, and to implement a main replacement program. MGUC seeks Commission approval to: (1) increase rates so as to produce an annual revenue increase of \$15,127,536; (2) approve a Rate of Return of 10.20%; (3) approve changes to tariff provisions; and (4) all other changes and suggestions made and supported in MGUC's testimony and exhibits.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscdockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscdockets@michigan.gov. If you require

assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____, **2021**. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon MGUC's attorney, Sherri A. Wellman, Miller, Canfield Paddock & Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, MI 48933.

Any person wishing to participate without intervention under Mich Admin Code, R 792.10413 (Rule 413), or file a public comment, may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. **U-20718**. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of MGUC's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets and at the office of Michigan Gas Utility Corporation. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

_____, 2021

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	Case No. U-20718
for authority to increase retail natural gas rates	)	
<u>and for other relief.</u>	)	

CERTIFICATION OF RICHARD F. STASIK

Richard F. Stasik, Director – State Regulatory Affairs, for Michigan Gas Utilities Corporation, states that he has provided the data required pursuant to the Rate Case Filing Requirements established by the Commission’s order dated July 31, 2017, issued in Case No. U-18238, and pursuant to these requirements, certifies the data so provided.

Dated: March 18, 2021



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

QUALIFICATIONS
OF
THEODORE T. EIDUKAS
PART I

1 **Q. Please state your name and business address.**

2 A. My name is Theodore Eidukas. My business address is WEC Energy Group, 231 West
3 Michigan Street, Milwaukee, Wisconsin 53203.

4

5 **Q. In what capacity are you employed?**

6 A. I am Vice President – Regulatory Affairs at WEC Energy Group, LC (“WEC”). WEC
7 Energy Group is the parent company of Michigan Gas Utilities Corporation (“MGUC”
8 or the “Company”).

9

10 **Q. Please address your responsibilities as Vice President – Regulatory Affairs at**
11 **WEC.**

12 A. I oversee all regulatory advocacy efforts across the holding company, including
13 proceedings before the Illinois Commerce Commission (“ICC”) and regulatory bodies

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 in other states. I also act as one of the lead in-house regulatory counsel for WEC's
2 utilities.

3 **Q. What is your educational and business experience?**

4 A. I hold a bachelor's degree, summa cum laude, in economics and political science from
5 Augustana College and a Juris Doctorate degree, cum laude, from Northwestern School
6 of Law. Before joining WEC in my current role in 2016, I practiced law in the field of
7 utility regulation for more than twenty years, most recently with the firm of Quarles &
8 Brady LLP.

9

10 **Q. On whose behalf are you offering this direct testimony?**

11 A. I am offering this direct testimony on behalf of MGUC.

12

13 **Q. Have you ever testified before a regulatory agency?**

14 A. Yes. I have testified before the ICC in the current rate case for North Shore Gas
15 Company ("NSG") and in multiple Rider QIP Reconciliation dockets for Peoples Gas
16 Coke and Light Company ("PGL"). Both NSG and PGL are sister operating utilities
17 of MGUC and operating subsidiaries of WEC.

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

THEODORE T. EIDUKAS
DIRECT TESTIMONY
PART II

1 **Purpose of Testimony**

2 **Q. What is the purpose of your testimony?**

3 A. The purpose of my testimony is to provide an overview of the 2022 projected test year
4 case, introduce the witnesses that will appear on behalf of MGUC, and provide support
5 for MGUC's capital spending forecast and test year special initiatives. I will also offer
6 some background on WEC and WBS Business Support ("WBS") and how those
7 entities support MGUC's operations.

8

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

10 A. No.

11

12 **Reasons for Filing this Rate Case**

13 **Q. Please describe MGUC.**

14 A. MGUC was originally incorporated as the Monroe Gas Light Company in 1859,
15 becoming MGUC in 1951 after almost 100 years of subsequent acquisitions and
16 mergers. While initially in the business of manufacturing gas for its customers, MGUC
17 converted its system to the delivery of natural gas in the early 1950s and expanded
18 dramatically throughout southern Michigan over the next 20 years. MGUC was
19 acquired in 1989 by what is now known as Aquila, and for a brief period was renamed
20 Aquila-Michigan. In 2006, Integrys Energy Group ("Integrys") acquired the utility and
21 restored the name of MGUC. Integrys was acquired and became part of the newly

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 formed WEC on June 29, 2015. MGUC continues to operate as a separate utility under
2 its new parent company, serving approximately 180,000 natural gas customers in and
3 around Grand Haven, Otsego, Benton Harbor, Coldwater, and Monroe.

4
5 **Q. Please describe WEC.**

6 A. WEC is a diversified energy company with \$29.0 billion in market cap as of year-end
7 2020, serving approximately 1.6 million electric and 2.9 million natural gas customers
8 in Wisconsin, Michigan, Minnesota, and Illinois. WEC is the 8th largest natural gas
9 distribution utility in the U.S. based on customers and the 11th largest publicly traded
10 utility in the U.S. measured by market value. WEC owns 49,000 miles of gas
11 distribution in addition to 70,100 miles of electric distribution and holds a 60%
12 ownership of American Transmission Company. Other energy infrastructure
13 investments include 100% ownership of Bluewater Gas Storage LLC and ownership
14 interests in several wind energy farms in the Midwest.

15
16 **Q. What are MGUC's overall business objectives?**

17 A. MGUC and its sister companies at WEC are focused on the fundamentals. Top
18 priorities are safety, world-class reliability, customer care, financial discipline, and
19 operating efficiency. By focusing on these fundamental objectives every day, WEC,
20 and of course MGUC, believes it can provide safe, reliable energy to its customers at a
21 reasonable cost.

22
23 **Q. What are some WEC corporate initiatives that impact MGUC and its customers?**

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 A. Between 2021 and 2025, WEC expects to invest more than \$16 billion across the
2 company with a focus on modernizing infrastructure, reshaping generation fleet for a
3 clean, reliable future, launching advanced metering functionality, and upgrading
4 systems and equipment. Included in these initiatives are programs that will benefit
5 MGUC and its customers:

- 6 • Enhancing customer care: bringing all utilities onto a single customer information
7 system platform, utilizing a common, enhanced-security platform, introducing a
8 customer-facing mobile app, and implementing advanced metering infrastructure.
- 9 • Enhancing reliability: pipeline replacement and system modernization projects.
- 10 • Methane reduction goal: a 30% decrease in the rate of methane emissions from the
11 natural gas distribution lines in our network of 30% per mile by the year 2030 from
12 a 2011 baseline.

13
14 WEC's long running focus on customer satisfaction has directly benefitted MGUC
15 customers since its acquisition in 2015. The WEC companies are able to leverage their
16 expertise across the four state jurisdictions, leveraging best practices in operations,
17 customer service, and other areas that directly impact the customers. In its procurement
18 practices, WEC is committed to developing a high-quality supply base to meet its
19 current and future business requirements across the Midwest with particular emphasis
20 on safety, supplier diversity, innovation, and cost reduction.

21

22 **Q. How do MGUC and WEC together serve local communities in Michigan?**

23 A. Local communities are served by MGUC and WEC in several ways. The Company
24 provides a positive economic impact by hiring employees in the communities it serves

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 and by obtaining services in many cases from local vendors and contractors. MGUC
2 also sponsors community events such as ice sculpting at the annual Ida Festival of
3 Lights. One of WEC's foundations, the WPS Foundation, supports MGUC directly,
4 reviewing grant proposals and directing donations to nonprofit organizations in
5 MGUC's service territories. For example, nearly \$1.7 million in funding was provided
6 for grants to education, arts and culture, environmental, health and human services as
7 well as community and neighborhood organizations through the WPS, Minnesota
8 Energy Resources, and MGUC service areas in 2020. WEC also provides matching
9 gift programs for contributions made by its employees, both active and retired, that
10 support local nonprofit organizations.

11

12 **Q. Please describe WBS and describe its relationship to MGUC?**

13 A. WBS is a non-regulated subsidiary of WEC. WBS provides a number of shared
14 services to WEC and its operating companies, including MGUC, under affiliated
15 interest agreements that apply to regulated and non-utility companies. The agreements
16 identify the types of services that the affiliates may provide and receive, as well as
17 certain requirements that are unique to WBS as a centralized service company. The
18 affiliate agreements regarding the arrangements between WEC and MGUC were
19 reviewed by the Commission in Case U-17682.

20

21 **Q. What services are provided to MGUC by WBS?**

22 A. WBS provides the following services to MGUC and its other affiliates:

- 23
 - Administrative (e.g., facility management, printing services);

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

- 1 • Communications (preparation and dissemination of information to employees,
2 customers, governmental officials, the public, and the media);
- 3 • Customer (e.g., meter reading and billing, credit, collections, call center operations,
4 market research);
- 5 • Environmental (e.g., assessments, investigations, remediation);
- 6 • Executive Management (e.g., general business planning, allocation of financial
7 resources);
- 8 • External Affairs (e.g., governmental relations, community support, regulatory
9 policy, rate administration);
- 10 • Finance (accounting, finance, treasury, tax, internal audit, risk management,
11 insurance, and related financial services);
- 12 • Human Resources (e.g. employment, compensation, benefits, wellness);
- 13 • Information Technology (e.g., telecommunications, electronic data processing
14 services, infrastructure, and application architecture);
- 15 • Legal and Governance (e.g., legal advice, regulatory matters, real estate,
16 shareholder services); and,
- 17 • Supply Chain (acquisition and provision of goods and services other than fuel,
18 energy commodities, or energy transmission).

19

20 WBS also provides the following specific services only to its regulated utility affiliates
21 such as MGUC:

- 22 • Operational Support and Development (e.g., design, construction and maintenance
23 of distribution lines, technical training, project management, geospatial services,
24 contract administration) and

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

- 1 • Wholesale Energy and Fuels (e.g., purchasing, marketing, and selling natural gas;
2 scheduling and dispatching deliveries; operating natural gas storage facilities).

3

4 **Q. How are costs allocated between the affiliated companies?**

5 A. The basic pricing principles included in the agreement are unchanged from the
6 arrangement that MGUC had with Integrys and its non-regulated service company,
7 IBS, that was in effect at the time of the filing of MGUC's most recent rate case, Case
8 No. U-17880. The services provided between affiliates that could involve MGUC
9 receiving or providing services would be priced as follows:

- 10 • Services that any Regulated Party provides to another Regulated Party will be
11 priced at cost;
- 12 • Services that any Regulated Party provides to any Non-Regulated
13 Party will be priced at the greater of cost or fair market value;
- 14 • Services that any Non-Regulated Party provides to any Regulated Party will
15 be priced at the lesser of cost or fair market value.

16

17 **Q. Is the arrangement between WBS and MGUC a benefit to MGUC and its**
18 **customers?**

19 A. Yes, it is. The services provided by WBS represent activity that any utility would need
20 to perform to effectively function as a separate company. WBS generates savings for
21 MGUC and its customers because of the efficiencies and synergies it brings in
22 providing services. This is so because with WBS providing the same services to all
23 operating utilities within WEC, the costs of these activities can be shared among all of
24 WBS' operating utility companies. Although some costs are variable to the size of the

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 company, many of these costs are fixed; therefore, a smaller company would pay a
2 higher amount in proportion to its relative size if the service was provided by an outside
3 party or fully staffed at the local level to perform the functions. MGUC could not self-
4 provide the same overall services provided by WBS at a lower cost.

5
6 In addition to economies of scale, MGUC receives the benefit of access to in-house
7 experts who can be retained only by larger companies. For example, many of the same
8 requirements that one utility may face from an environmental or safety compliance
9 perspective will impact other companies within WEC. Having one combined group
10 providing support and research not only lowers the costs but helps to ensure strong
11 compliance programs with broad internal institutional knowledge.

12

13 **Q. When were MGUC's base rates last reset?**

14 A. MGUC's rates were last reset in Case No. U-17880, which was concluded with the
15 Commission's approval of the settlement reached between MGUC, Staff, and the
16 Michigan Attorney General's Office.

17

18 **Q. What is the level of annual increase in base rates that MGUC is seeking in this**
19 **case?**

20 A. MGUC's direct case supports a total revenue increase of \$15,127,536 million in its
21 base rates, which represents an increase of 10.7% when compared to the Company's
22 current base rates.

23

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 **Q. What are the key drivers of rate case as compared to MGUC's most recent base**
2 **rate case?**

3 A. The revenue requirement associated with capital investments made by MGUC since its
4 last rate case is the most significant upward driver. This driver is responsible for a
5 \$23.4 million in revenue requirement increase. However, there are three downward-
6 drivers that counteract this increase. These drivers are:

- 7 • Operations and maintenance expenses that are \$4.1 million lower than they were
8 when MGUC's base rates were last approved;
- 9 • Increased sales that result in a \$4.8 million lower revenue requirement as
10 compared to MGUC's last rate case; and,
- 11 • Reduced tax expense associated with the TCJA, which reduces MGUC's revenue
12 requirement by \$4.6 million on a comparative basis.

13
14 **Q. Is MGUC seeking any changes in its authorized return or capital structure?**

15 A. Yes. As covered in greater detail in Witnesses Bulkley and Zgonc, the Company is
16 seeking a Return on Common Equity of 10.2% and a capital structure that includes
17 52.5% of permanent equity.

18
19 **Q. Please introduce the witnesses that MGUC is providing to support its request for**
20 **rate relief.**

21 A. MGUC's witnesses include:

- 22 1. Financial schedules, cost of capital, capital structure and incentive
23 compensation – Joseph Zgonc

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

- 1 2. Return on equity and equity portion of capital structure – Ann Bulkley of
- 2 Concentric Advisors
- 3 3. Capital Investments made by MGUC since its last rate case and capital
- 4 projects to be supported by the proposed Main Replacement Program
- 5 (“MRP”) Surcharge Rider – Nathan Lee
- 6 4. Sales forecast – Jared Peccarelli
- 7 5. Cost of service – Aaron Nelson
- 8 6. Rate design & tariff updates – Shannon Burzycki

9

10 **Q. In its approval of the Michigan Strategic Energy Assessment Final Report in Case**

11 **No. U-20464, the Commission ordered Staff to work with utilities to propose**

12 **natural gas demand response tariffs in the utilities’ next round of natural gas rate**

13 **cases filed after the date of the order (September 11, 2019). Has MGUC**

14 **participated in this process?**

15 A. Yes, MGUC participated in the first meeting coordinated by Staff on January 27,

16 2020.

17

18 **Q. Has MGUC developed a new natural gas demand response tariff for approval in**

19 **this proceeding?**

20 A. Yes, MGUC has developed a proposed pilot tariff for this purpose. This proposed pilot

21 tariff will be introduced by MGUC Witness Shannon Burzycki.

22

23 **Q. Will MGUC be introducing any other new tariffs in this proceeding?**

DIRECT TESTIMONY OF
THEODORE T. EIDUKAS

1 A. Yes. The Company will be proposing the additional of two new tariffs as part of this
2 proceeding. First, MGUC will propose a new medium-sized commercial class. Second,
3 the MGUC will be proposing the addition of a MRP Surcharge Rider. Both new tariffs
4 will be introduced by MGUC Witness Shannon Burzycki.

5

6 **Q. Does this conclude your pre-filed direct testimony at this time?**

7 A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

DIRECT TESTIMONY AND EXHIBITS OF

JOSEPH L. ZGONC

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

QUALIFICATIONS
OF
JOSEPH L. ZGONC
PART I

1 **Q. Please state your name, business address and position.**

2 A. My name is Joseph Zgonc. My business address is 231 West Michigan Street,
3 Milwaukee, Wisconsin 53203. I am employed by WEC Business Services, LLC (“WBS”), a
4 subsidiary of WEC Energy Group, Inc. (“WEC”), as Manager – Financial and Regulatory Planning.

5 **Q. For whom are you providing testimony?**

6 A. I am providing testimony on behalf of Michigan Gas Utilities Corporation (“MGUC” or the
7 “Company”), which is a subsidiary of WEC.

8 **Q. Please describe briefly your educational, professional, and utility background.**

9 A. I received a Bachelor of Business Administration Degree from the University of Cincinnati,
10 College of Business in 1994. I joined the finance staff at Wisconsin Electric Power Company
11 (“WEPCO”) in 2012 and have performed various roles within budgeting, accounting, and rate
12 cases. Prior to WEPCO, I worked at Utilities International, Inc. for 15 years, rising to the position
13 of Principal. Utilities International is the industry leader in planning, budgeting, regulatory,
14 revenue and accounting software solutions for the utilities sector. As a Principal at

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 Utilities International, I was responsible for selling and managing consulting and software
2 installation projects that focused on financial and regulatory planning, budgeting, and reporting at
3 large investor owned utilities.

4 **Q. Have you previously testified before any regulatory agency?**

5 A. Yes, I have. I have submitted testimony before the Public Service Commission of Wisconsin and
6 the Illinois Commerce Commission.

7 **Q. What is the purpose of your pre-filed direct testimony?**

8 A. The purpose of my pre-filed direct testimony is to provide an explanation of the methodology used
9 to develop MGUC's revenue deficiency for the 2022 projected test year.

10 **Q. Are you sponsoring any exhibits in this proceeding?**

11 A. Yes, I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Title</u>
A-1	A1	Revenue Deficiency (Sufficiency)
A-1	A2	Financial Metrics - Financial Basis
A-2	B1	Rate Base
A-2	B2	Utility Plant
A-2	B3	Depreciation Reserve and Other Deductions
A-2	B4	Working Capital
A-3	C1	Adjusted Net Operating Income
A-3	C2	Revenue Conversion Factor
A-3	C3	Operating Revenue
A-3	C4	Cost of Gas Sold

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

<u>Exhibit</u>	<u>Schedule</u>	<u>Title</u>
A-3	C5	Operation and Maintenance Expenses
A-3	C6	Depreciation and Amortization Expenses
A-3	C7	General Taxes
A-3	C8	Federal Income Taxes
A-3	C9	State Income Taxes
A-3	C10	Other (or Local) Taxes
A-3	C11	Allowance for Funds Used During Construction
A-4	D1	Rate of Return Summary
A-4	D2	Cost of Long-Term Debt
A-4	D3	Cost of Short-Term Debt
A-4	D4	Cost of Preferred Stock
A-4	D5	Cost of Common Shareholders' Equity
A-11	A1	Revenue Deficiency (Sufficiency)
A-11	A2	Financial Metrics - Ratemaking Basis
A-12	B1	Projected Rate Base
A-12	B2	Total Utility Plant
A-12	B3	Depreciation Reserve and Other Deductions
A-12	B4	Working Capital
A-12	B5	Summary of Actual and Projected Gas Capital Expenditures
A-12	B5.1	Underground Gas Storage Capital Expenditures
A-12	B5.2	Transmission Capital Expenditures
A-12	B5.3	Distribution Plant Capital Expenditures
A-12	B5.4	General Capital Expenditures
A-12	B5.5	Intangible Capital Expenditures

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

<u>Exhibit</u>	<u>Schedule</u>	<u>Title</u>
A-13	C1	Adjusted Net Operating Income
A-13	C2	Projected Revenue Conversion Factor
A-13	C3	Projected Operating Revenue
A-13	C4	Cost of Gas Sold
A-13	C5	Projected Operation and Maintenance Expenses
A-13	C6	Projected Depreciation and Amortization Expenses
A-13	C7	Projected General Taxes
A-13	C8	Projected Federal Income Taxes
A-13	C9	Projected State Income Taxes
A-13	C10	Other (or Local) Taxes
A-13	C11	Allowance for Funds Used During Construction
A-14	D1	Projected Rate of Return Summary
A-14	D2	Cost of Long-Term Debt
A-14	D3	Cost of Short-Term Debt
A-14	D4	Cost of Preferred Stock
A-14	D5	Cost of Common Shareholders' Equity
A-17	C1	Operation and Maintenance Expenses - Gas Utility - Historical and Forecasted
A-17	C2	Known and Measurable Adjustment for Manufactured Gas Plant Remediation
A-17	C3	Known and Measurable Adjustment for Underground Storage Expenses - Wells
A-17	C4	Known and Measurable Adjustment for Underground Storage Expenses - Other

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

<u>Exhibit</u>	<u>Schedule</u>	<u>Title</u>
A-17	C5	Known and Measurable Adjustment for Transmission Operations Mains Expense
A-17	C6	Known and Measurable Adjustment for Transmission Operations Other Expenses
A-17	C7	Known and Measurable Adjustment for Transmission Maintenance of Mains
A-17	C8	Known and Measurable Adjustment for Distribution Operations Mains and Service Expenses
A-17	C9	Known and Measurable Adjustment for Distribution Operations Other Expenses
A-17	C10	Known and Measurable Adjustment for Distribution Maintenance of Mains
A-17	C11	Known and Measurable Adjustment for Distribution Maintenance of Measuring and Regulating Station Equipment - General
A-17	C12	Known and Measurable Adjustment for Distribution Maintenance of Services
A-17	C13	Known and Measurable Adjustment for Distribution Maintenance of Meters and House Regulators
A-17	C14	Known and Measurable Adjustment for Customer Accounts Expense - Meter Reading
A-17	C15	Known and Measurable Adjustment for Customer Accounts Expense - Customer Records and Collection

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

<u>Exhibit</u>	<u>Schedule</u>	<u>Title</u>
A-17	C16	Known and Measurable Adjustment for Customer Accounts Expense - Uncollectible Accounts
A-17	C17	Known and Measurable Adjustment for Administrative and General - Injuries and Damages Expenses
A-17	C18	Known and Measurable Adjustment for Administrative and General - Employee Pensions and Benefits Expenses
A-17	C19	Known and Measurable Adjustment for Administrative and General - Miscellaneous General Expenses
A-17	C20	Estimate of Inflation for 2020, 2021, and 2022
A-18		Annual Incentive Plan for Non-Executives
A-19		2021 MGU Non-Executive Incentive Plan Overview (Confidential and Public Versions)

1

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

3 A. Yes, they were.

4

5 **Q. Please provide a summary of the subjects you will address in your testimony.**

6 A. I provide testimony and evidence regarding:

- 7 1. The revenue deficiency, including
- 8 a. Capital Structure,
- 9 b. Inflation Rates,
- 10 c. Operations and Maintenance (“O&M”) Expenses,
- 11 d. Known and Measurable (“K&M”) Items,
- 12 e. Depreciation Rates;
- 13
- 14 2. Incentive Compensation; and,
- 15 3. Gas Costs and Revenues.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Q. Please describe the most recent rate relief obtained by MGUC.**

2 A. MGUC's most recent rate case, Case No. U-17880 was based on a 2016 test year. A settlement
3 was reached and approved by the Michigan Public Service Commission ("MPSC" or the
4 "Commission") granting rate relief of \$3.4 million, based on a return on common equity of 9.90%
5 and a 52.00% equity layer in permanent capital, effective January 1, 2016.

6 MGUC was also authorized to continue to invest capital in projects that reduce MGUC's overall
7 system risk in accordance with MGUC's Distribution Integrity Management Program that is filed
8 with the Commission. The legacy bare steel pipe replacement project was completed in 2020.

9 MGUC's rates for retail gas service established in Case No. U-17880 do not reflect the projected
10 costs of providing retail gas service, and MGUC requires further rate relief.

11 On May 14, 2020, MUGC filed an application in Case No. U-20797 for temporary relief in the
12 form of deferred accounting in the amount of \$ 5 million related to expenses pertaining to capital
13 investments made since its last rate case. On July 23, 2020, the Commission issued its order in Case
14 No. U-20797 granting MGUC the request deferred accounting approval from January 1, 2021
15 through December 31, 2021, or until new base rates are authorized in Case No. U-20718.

16 **Q. Please explain, generally, why rate relief is sought at this time.**

17 A. As detailed in my testimony, MGUC expects a significant revenue deficiency in 2022 driven by
18 many reasons, including but not limited to: (1) investing in capital projects that upgrade the gas
19 transmission and distribution systems, (2) investing in the Partello transmission pipeline
20 replacement and field structures and equipment, (3) investing in advanced metering infrastructure,
21 and (4) projecting a higher cost of capital in the 2022 test year as supported by the testimony of
22 Witness Bulkley.

23 To date MGUC has been able to offset the increased revenue requirement associated with capital
24 additions with increases in sales margin and reductions in O&M expenses. Specifically, the
25 Company's sales margin increased from 2016 by over \$4 million. As for its O&M expenses, while

DIRECT TESTIMONY AND EXHIBITS OF
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1 general inflation, not including K&M items, is projected to increase costs by 6.37% from 2019 to
2 2022 (see Exhibit A-17, Schedule C20), MGUC is forecasting decreases of \$ 4.1 million in the test
3 year when compared to 2016.

4 Going forward, looking at the 2022 projected test year, the growth in revenues is not expected to
5 keep pace with the increase in revenue requirement from the return on and of the additional
6 investments in plant required by MGUC.

7 **The Revenue Deficiency**

8 **Q. What is the amount of rate relief MGUC is seeking in this proceeding?**

9 A. MGUC's analysis of the test year ending December 31, 2022 indicates a need for an annual rate
10 increase of \$15,136,352, or 10.7%, for retail gas operations. This increase is based on the rates
11 authorized in the Commission's December 11, 2015 Order Approving Settlement Agreement in
12 Case No. U-17880 and a proposed return on common equity of 10.20%, which is supported by the
13 direct testimony of Witness Bulkley of Concentric Energy Advisors, Inc. ("Concentric").
14 The rates sponsored by Witness Burzycki are designed to produce the requested revenue
15 requirement.

16 **Q. What test period is MGUC's proposed rate increase based on?**

17 A. MGUC has used a projected test year ending December 31, 2022.

18 **2019 Historic Test Year Exhibits**

19 **Q. Please explain Schedule A1 of Exhibit A-1.**

20 A. Schedule A1 of Exhibit A-1 calculates MGUC's 2019 historic test year revenue sufficiency based
21 on its rate base, adjusted net operating income, rate of return, and revenue conversion factor. This

DIRECT TESTIMONY AND EXHIBITS OF
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1 schedule develops the 2019 Total Company revenue sufficiency of \$6.6 million, as shown on Line
2 16, using a 9.90% return on equity. The component parts of this schedule are taken from the various
3 sources indexed to the left of these amounts.

4 **Q. Please explain Schedule A2 of Exhibit A-1.**

5 A. Schedule A2 of Exhibit A-1 provides 2015 through 2019 historical year financial metrics. The
6 ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest
7 Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the
8 Dividend, Common Dividend Payout Ratio, Permanent Capitalization Balances and Percentages.

9 **Q. Please explain Schedule B1 of Exhibit A-2.**

10 A. Schedule B1 of Exhibit A-2 calculates MGUC's 2019 historic test year rate base. The component
11 parts of this schedule are taken from the various sources indexed to the left of these amounts.

12 **Q. Please explain Schedule B2 of Exhibit A-2.**

13 A. Schedule B2 of Exhibit A-2 calculates MGUC's 2019 historic test year utility plant.

14 **Q. Please explain Schedule B3 of Exhibit A-2.**

15 A. Schedule B3 of Exhibit A-2 depicts MGUC's 2019 historic test year accumulated provision for
16 depreciation.

17 **Q. Please explain Schedule B4 of Exhibit A-2.**

18 A. Schedule B4 of Exhibit A-2 calculates MGUC's 2019 historic test year working capital.

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Q. Please explain Schedule C1 of Exhibit A-3.**

2 A. Schedule C1 of Exhibit A-3 calculates MGUC's 2019 historic test year adjusted net operating
3 income.

4 **Q. Please explain Schedule C2 of Exhibit A-3.**

5 A. Schedule C2 of Exhibit A-3 calculates MGUC's 2019 historic test year gross revenue conversion
6 factor.

7 **Q. Please explain Schedule C3 of Exhibit A-3.**

8 A. Schedule C3 of Exhibit A-3 calculates MGUC's 2019 historic test year total revenue.

9 **Q. Please explain Schedule C4 of Exhibit A-3.**

10 A. Schedule C4 of Exhibit A-3 calculates MGUC's 2019 historic test year cost of gas.

11 **Q. Please explain Schedule C5 of Exhibit A-3.**

12 A. Schedule C5 of Exhibit A-3 calculates MGUC's 2019 historic test year total O&M expense,
13 exclusive of the cost of gas.

14 **Q. Please explain Schedule C6 of Exhibit A-3.**

15 A. Schedule C6 of Exhibit A-3 depicts MGUC's 2019 historic test year total depreciation and
16 amortization expense.

17 **Q. Please explain Schedule C7 of Exhibit A-3.**

18 A. Schedule C7 of Exhibit A-3 calculates MGUC's 2019 historic test year total for taxes other than
19 income taxes.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Q. Please explain Schedule C8 of Exhibit A-3.**

2 A. Schedule C8 of Exhibit A-3 depicts MGUC's 2019 historic test year federal income taxes.

3 **Q. Please explain Schedule C9 of Exhibit A-3.**

4 A. Schedule C9 of Exhibit A-3 depicts MGUC's 2019 historic test year state income taxes.

5 **Q. Please explain Schedule C10 of Exhibit A-3.**

6 A. Schedule C10 of Exhibit A-3 depicts MGUC's 2019 historic test year local taxes.

7 **Q. Please explain Schedule C11 of Exhibit A-3.**

8 A. Schedule C11 of Exhibit A-3 depicts MGUC's 2019 historic test year AFUDC.

9 **Q. Please explain Schedule D1 of Exhibit A-4.**

10 A. Schedule D1 of Exhibit A-4 develops MGUC's 2019 historic test year overall rate of return of
11 6.95% (shown on Line 22) based on MGUC's 13-month average capital structure, and a 9.90%
12 ROE.

13 **Q. Please explain Schedule D2 of Exhibit A-4.**

14 A. Schedule D2 of Exhibit A-4 develops MGUC's 2019 historic test year embedded cost of long-term
15 debt of 3.58%, based on a 13-month average, as shown on Line 20.

16 **Q. Please explain Schedule D3 of Exhibit A-4.**

17 A. Schedule D3 of Exhibit A-4 develops MGUC's 2019 historic test year cost of short-term debt of
18 3.01%, based on a 13-month average, as shown on Line 26.

19

20 **Q. Please explain Schedule D4 of Exhibit A-4.**

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

A. Schedule D4 of Exhibit A-4 indicates that MGUC has no preferred equity outstanding, as shown on Line 2.

Q. Please explain Schedule D5 of Exhibit A-4.

A. Schedule D5 of Exhibit A-4 develops MGUC's 13-month average balance of Adjusted Common Equity of \$135.0 million for the 2019 historic test year, as shown on Line 16.

2022 Forecast Test Year Exhibits

Q. Please explain Schedule A1 of Exhibit A-11.

A. Schedule A1 of Exhibit A-11 calculates MGUC's 2022 projected test year revenue deficiency based on its rate base, adjusted net operating income, rate of return, and revenue conversion factor. This schedule indicates that the 2022 Total Company revenue deficiency is \$15,136,352 million, or 10.7%, based on the rates authorized in the Commission's December 11, 2015 Order Approving Settlement Agreement in Case No. U-17880, and a proposed 10.20% return on equity. The component parts of this schedule are taken from the various sources indexed to the left of each value.

Q. Please explain Schedule A2 of Exhibit A-11.

A. Schedule A2 of Exhibit A-11 provides 2022 projected test year financial metrics with and without rate relief on a ratemaking basis. The ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the Dividend, Common Dividend Payout Ratio, and Permanent Capitalization Balances and Percentages.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Rate Base**

2 **Q. Please explain Schedule B1 of Exhibit A-12.**

3 A. Schedule B1 of Exhibit A-12 calculates MGUC's 2022 projected test year rate base.
4 The component parts of this schedule are taken from the various sources indexed to the left of these
5 amounts.

6 **Q. Please explain Schedule B2 of Exhibit A-12.**

7 A. Schedule B2 of Exhibit A-12 depicts MGUC's 2022 projected test year utility plant. To arrive at
8 the 2022 projected test year utility plant, the September 30, 2020 actual balance of utility plant was
9 projected forward using MGUC's 2020, 2021, and 2022 construction budgets.

10 **Q. Please explain Schedule B3 of Exhibit A-12.**

11 A. Schedule B3 of Exhibit A-12 depicts MGUC's 2022 projected test year accumulated provision for
12 depreciation. To arrive at the 2022 projected test year accumulated provision for depreciation, the
13 September 30, 2020 actual balance of accumulated provision for depreciation was projected
14 forward using MGUC's existing plant and 2020, 2021, and 2022 construction budgets.

15 **Q. Please explain Schedule B4 of Exhibit A-12.**

16 A. Schedule B4 of Exhibit A-12 calculates MGUC's 2022 projected test year working capital.

17 **Q. Please explain Schedule B5 of Exhibit A-12.**

18 A. Schedule B5 and associated sub schedules of Exhibit A-12 depict MGUC's capital expenditures by
19 function and FERC plant account for the 2019 historical year, projected bridge period and 2022
20 test year.

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Operating Income**

2 **Q. Please explain Schedule C1 of Exhibit A-13.**

3 A. Schedule C1 of Exhibit A-13 calculates MGUC's 2022 projected test year adjusted net operating
4 income. Line 8 Regulatory Items, Debits and Credits of \$2.5M is the amortization of the 2021
5 Revenue Requirement deferral authorized in docket U-20797.

6

7 **Q. Please explain Schedule C2 of Exhibit A-13.**

8 A. Schedule C2 of Exhibit A-13 calculates MGUC's 2022 projected test year gross revenue conversion
9 factor.

10 **Q. Please explain Schedule C3 of Exhibit A-13.**

11 A. Schedule C3 of Exhibit A-13 calculates MGUC's 2022 projected test year total revenue.

12 **Q. Please explain Schedule C4 of Exhibit A-13.**

13 A. Schedule C4 of Exhibit A-13 calculates MGUC's 2022 projected test year cost of gas.

14 **Q. Please explain Schedule C5 of Exhibit A-13.**

15 A. Schedule C5 of Exhibit A-13 calculates MGUC's 2022 projected test year total O&M expense,
16 exclusive of the cost of gas by function.

17 **Q. Please explain Schedule C6 of Exhibit A-13.**

18 A. Schedule C6 of Exhibit A-13 depicts MGUC's 2022 projected test year total depreciation and
19 amortization expense.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Q. Please explain Schedule C7 of Exhibit A-13.**

2 A. Schedule C7 of Exhibit A-13 calculates MGUC's 2022 projected test year total for taxes other than
3 income taxes.

4 **Q. Please explain Schedule C8 of Exhibit A-13.**

5 A. Schedule C8 of Exhibit A-13 depicts MGUC's 2022 projected test year federal income taxes.

6 **Q. Please explain Schedule C9 of Exhibit A-13.**

7 A. Schedule C9 of Exhibit A-13 depicts MGUC's 2022 projected test year state income taxes.

8 **Q. Please explain Schedule C10 of Exhibit A-13.**

9 A. Schedule C10 of Exhibit A-13 depicts MGUC's 2022 projected test year local taxes.

10 **Q. Please explain Schedule C11 of Exhibit A-13.**

11 A. Schedule C11 of Exhibit A-13 depicts MGUC's 2022 projected test year AFUDC.

12 **Capital Structure**

13 **Q. Please explain Schedules D1 of Exhibit A-14.**

14 A. Schedule D1 of Exhibit A-14 develops MGUC's 2022 projected test year overall rate of return of
15 5.72%, shown on Line 22, Column G based on MGUC's 13-month average common equity ratio
16 set at 52.50% with a 10.20% ROE, as shown on Line 6.

17 **Q. What adjustments were made to the equity portion of MGUC's capital structure?**

18 A. MGUC has removed certain accounts both from the 2019 historic test year and the 2022 projected
19 test year. For both the 2019 historic test year and the 2022 projected test year Trade Name,

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

Goodwill and the deferred income taxes associated with Goodwill were removed from MGUC's equity balance, which reduces the revenue requirement.

Q. What adjustments were made to MGUC's overall capital structure?

A. For both the 2019 historic test year and the 2022 projected test year, interest bearing accounts in working capital were removed from the capital structure to prevent MGUC from earning a return on these items. This adjustment included items related to:

1. GCR over collections,
2. Customer advances and deposits,
3. Energy Optimization, and
4. Post-Retirement Health – Admin and Non-Admin.

This resulted in a reduction in the capital, which reduces the revenue requirement.

Q. Please explain Schedules D2 of Exhibit A-14.

A. Schedule D2 of Exhibit A-14 develops MGUC's 2022 projected test year embedded cost of long term debt of 3.35%, based on a 13-month average, as shown on Line 20. There is one new debt issue for the 2022 test year, a \$20 million 30-year issuance in September 2022, with an interest rate of 4.20%.

Q. Please explain Schedules D3 of Exhibit A-14.

A. Schedule D3 of Exhibit A-14 develops MGUC's 2022 projected test year cost of short-term debt of 3.26%, based on a 13-month average, as shown on Line 26. The forecasted borrowing rate includes fixed fees for credit facility fees and amortization along with guarantee fees.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Q. How did you determine the cost rates of long and short term debt reflected in the weighted**
2 **cost of capital?**

3 A. The cost rate of long term debt reflects the embedded weighted cost of existing long term debt as
4 adjusted for forecasted new issues. The forecasted 2022 rate includes a forecasted benchmark
5 Treasury at 2.20% plus a 200 basis point spread. The 200 basis point spread can be split 110 basis
6 points for the historical credit spread between Treasuries and A rated utilities when the markets are
7 stable, 10 basis points for private placement versus public market, 5 basis points for small issuance
8 size and 75 basis point spread risk for market volatility. MGUC estimated a test year incremental
9 short-term debt rate of 1.00% using the forecasted, Commercial Paper 1 month rate plus a 70 basis
10 point spread for A2/P2 versus AA Commercial Paper and market volatility.

11 **Q. Please explain Schedules D4 of Exhibit A-14.**

12 A. Schedule D4 of Exhibit A-14 indicates that MGUC has no preferred equity outstanding, as shown
13 on Line 2.

14 **Q. Please explain Schedules D5 of Exhibit A-14.**

15 A. Schedule D5 of Exhibit A-14 develops MGUC's 13-month average balance of Adjusted Common
16 Equity of \$171.6 million for the 2022 projected test year, as shown on Line 16. MGUC requests a
17 10.20% ROE for the 2022 projected test year in this general rate case proceeding, as supported by
18 Witness Bulkley.

19 **Q. Does MGUC present any other evidence on cost of capital?**

20 A. Yes, it does. Witness Bulkley provides evidence on MGUC's cost of equity. She presents
21 analytical studies employing various industry models.

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Q. Please explain Schedules C20 of Exhibit A-17.**

2 A. Schedule C20 of Exhibit A-17 calculates the non-labor inflation rates for 2020, 2021 and 2022
3 using a methodology similar to that used by MGUC in Case No. U-17880. The non-labor inflation
4 rates calculated are 1.595% for 2020, 2.375% for 2021, and 2.275% for 2022.

5 **O&M Expenses**

6 **Q. Please describe how MGUC developed 2022 O&M expenses.**

7 A. MGUC started with 2019 actual O&M expenses and inflated them to 2022 using the rates
8 developed on Schedules C20 of Exhibit A-17 for non-labor. The labor inflation factors used were
9 2.53% for 2020, 2.80% for 2021 and 2.98% in 2022. The labor inflation factors were calculated
10 by using the projected general wage increases by pay group (contract rates for union employees)
11 and weighting them by September 2020 MGUC headcount. MGUC then adjusted this 2022 O&M
12 expense value for the K&M items, as described later in my testimony.

13 **Q. Please explain Schedules C1 of Exhibit A-17.**

14 A. Exhibit A-1 develops the O&M costs for MGUC's 2022 projected test year. This exhibit starts
15 with 2019 actual O&M amounts. The 2019 expenses were first inflated at the estimated inflation
16 factors as calculated on Schedules C20 of Exhibit A-17. The O&M accounts were further adjusted
17 for K&M items.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

K&M Items

Q. Please describe the K&M adjustments included in the 2022 projected test year O&M expenses, as detailed on Schedules C1 of Exhibit A-17 compared to actual O&M expenses from the 2019 historic test year.

A. There are 18 K&M adjustments. MGUC has defined K&M items to be any O&M cost item that was increased (or decreased) at a rate other than the rates of inflation calculated on Schedules C20 of Exhibit A-17.

Each of these K&M adjustments is discussed in further detail below.

Q. Please explain Schedules C2 of Exhibit A-17.

A. Schedules C2 of Exhibit A-17 calculate the K&M increase regarding costs to remediate former manufactured gas plant (“MGP”) sites. In its March 30, 1994 order in Case No. U-10503, and its November 10, 2005 order in Case No. U-14657, the Commission authorized MGUC to employ deferred accounting treatment for costs associated with the remediation of former MGP sites. Since 2002, MGUC has conducted remediation activities at former MGP sites located in:

1. Benton Harbor (Remedial investigations, source removal, groundwater monitoring, and property acquisition),
2. Cadillac (Remedial investigations, groundwater monitoring, source removal, and property acquisition),
3. Coldwater Race Street (Remedial investigations, source removal, groundwater monitoring, and closure documentation),
4. Grand Haven (Remedial investigations, source removal, and groundwater monitoring),
5. Hillsdale (Remedial investigations, source removal, and groundwater monitoring),
6. Otsego (Remedial investigations, source removal, groundwater monitoring, and property acquisition),

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7. South Haven (Remedial investigations, source removal, and property acquisition),
8. Sturgis (Groundwater monitoring and closure documentation),
9. Traverse City (Groundwater monitoring),
10. Coldwater Chicago Street (Remedial investigations and source removal), and
11. Monroe (Remedial investigations).

On page 2 of 2 of Schedules C2 of Exhibit A-17, MGUC calculated the 2022 projected test year amortization expense in accordance with the Commission's current practice of amortizing deferred MGP remediation costs on a vintage basis over ten years. Therefore, for the 2022 projected test year, MGUC has calculated a K&M increase of \$37,154 in Account 735, as shown on Line 9 of page 1 of 2 of Schedules C2 Exhibit A-17.

Q. Please explain Schedules C3 of Exhibit A-17.

A. Schedules C3 of Exhibit A-17 calculate the K&M adjustment associated with Corrosion Logs. Estimated program costs for periodic integrity assessments associated with storage wells. Total cost of \$300,000 covers expenses over a 10-year period. The Company estimates a Known and Measurable increase of \$30,000 for the 2022 test year.

The United States Department of Transportation ("USDOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") published the final rule to amend its minimum safety standards for underground natural gas storage facilities ("UNGSTs") on February 20, 2020. The final rule amends the interim final rule published on December 19, 2016 that established regulations in response to the 2015 Aliso Canyon incident and the subsequent mandate in section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016. Congress issued the mandate to PHMSA following a large-scale natural gas leak at the Aliso Canyon UNGST in Southern California on October 23, 2015.

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1
2 The final rule requires operators of UNGSFs to establish a schedule for conducting an initial
3 baseline assessment, and requires that operators conduct periodic reassessments of underground
4 storage wells. The corrosion log program complies with the requirements of the PHMSA UNGSF
5 final rule.

6
7 **Q. Please explain Schedules C4 of Exhibit A-17.**

8 A. Schedules C4 of Exhibit A-17 calculate the K&M adjustment associated with Transmission
9 Integrity Management Program (“TIMP”) Implementation. Estimated program costs for periodic
10 material verifications on the high pressure gas gathering pipeline. Total cost of \$500,000 covers
11 expenses over a 10-year period. The Company estimates a Known and Measurable increase of
12 \$50,000 for the 2022 test year.

13 PHMSA issued significant new regulations in response to the 2010 natural gas explosion in San
14 Bruno, California that killed eight people, injured 51, and destroyed nearly 40 homes, and other
15 similar incidents. These regulations, collectively referred to as the Mega Rule, aim to improve
16 federal pipeline safety laws. In particular, the Mega Rule addresses what federal regulators found
17 to be operators’ inadequate integrity management programs. The Mega Rule focuses on increasing
18 the safety of onshore gas transmission pipelines and improving documentation and data collection
19 for added safety and efficiency.

20
21 The material verification program at MGU complies with the PHMSA final transmission rule as
22 published in September 2019.

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1 **Q. Please explain Schedules C5 of Exhibit A-17.**

2 A. Schedules C5 of Exhibit A-17 calculate the K&M adjustment associated with Casing Vent
3 Replacements. Casings are required to have vents, the Company hires contractors to install the
4 vents because of the depth of the casings - MGU crews do not have the necessary equipment or
5 resources to install them. The Company estimates a K&M increase of \$175,000 for the 2022 test
6 year.

7 **Q. Please explain Schedules C6 of Exhibit A-17.**

8 A. Schedules C6 of Exhibit A-17 calculate the K&M adjustment associated with Gas Sampling which
9 is required by Transmission Integrity Management Program ("TIMP") and new Michigan Gas
10 Technical Standards, Case No. U-20608, Rule 460.2381, effective August 20, 2020, in which MGU
11 will be required to test the gas we deliver to customers for hydrogen sulfide, carbon dioxide,
12 oxygen, and water content. The Company estimates a K&M increase of \$20,000 for the 2022 test
13 year.

14 **Q. Please explain Schedules C7 of Exhibit A-17.**

15 A. Schedules C7 of Exhibit A-17 calculate the K&M adjustment associated with new TIMP rules.
16 New TIMP rules require additional O&M tasks to be completed. This will result in a shift from
17 capital to O&M work in the field. These tasks include material verification, pressure testing, and
18 compliance with the new PHMSA "Mega Rule" regulations, which are new regulations aiming to
19 improve federal pipeline safety laws. In particular, the Mega Rule addresses what federal
20 regulators found to be operators' inadequate integrity management programs. The Mega Rule
21 overhauled 49 C.F.R. §§ 191 and 192, safety regulations that apply to natural gas local
22 distribution companies like MGUC.

23

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1 This incremental O&M work will be completed by current MGUC field employees or contractors.
2 The Company anticipates being required to perform opportunistic material verification on our
3 transmission pipelines 2-3 times per year at \$15,000 – \$20,000 per location for an estimated K&M
4 increase of \$50,000 for the 2022 test year.

5 **Q. Please explain Schedules C8 of Exhibit A-17.**

6 A. Schedules C8 of Exhibit A-17 calculate the K&M adjustment associated with Account 874,
7 Distribution Operations Mains and Services Expenses. There are multiple drivers to this K&M
8 adjustment totaling an increase of \$314,000.

9 The first is increased overtime or additional staffing for Insolated Steel Services. As a result of the
10 MPSC non-compliance NC 316629 received, MGUC has generated an additional 7,100 records to
11 monitor throughout a 10-year cycle on an on-going basis. Completing an additional 710 records
12 annually at a loaded cost of \$59 per hour and the expectancy of approximately 3 tasks per hour
13 equates to about \$14,000 of additional O&M work. The Company estimates a K&M increase of
14 \$14,000 for the 2022 test year.

15 The second is increased overtime for Locators. This is to accommodate the increase of locating
16 requirements related to the increase in damage prevention promotion by our Company, Miss Dig
17 and the reporting of damages as required by the MPSC. The scale and quantity of locates continue
18 to expand with the requirement to locate during off hours more frequently and the expansion of
19 normal work days to 10-hour days during peak construction months. The Company estimates a
20 K&M increase of \$100,000 for the 2022 test year.

21
22 The third is incremental costs associated with Damage Prevention. These incremental costs come
23 from several aspects of the Company's Damage Prevention Program. Increased time for employees
24 to report damaging parties to the MPSC as a part of the MPSC's real-time reporting initiative and
25 our need to reduce third-party damages from repeat offenders. MGUC has also incurred additional

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costs for its presence in the communities sharing the Damage Prevention message, which increases the number of locate requests and the increased scope of the tickets. The Company estimates a K&M increase of \$50,000 for the 2022 test year.

The fourth driver is associated with the Pipeline Safety Management System (“PSMS”). The American Gas Association has recommended that member companies implement a PSMS. The Company plans to hire a full-time employee to implement and administer this program. In addition, current MGUC employees in the Engineering and Compliance departments will be involved in this program. The internal labor for these employees that would have normally been charged to capital work, will be decreasing, resulting in an increase in O&M. The Company estimates a K&M increase of \$150,000 for the 2022 test year.

Q. Please explain Schedules C9 Exhibit A-17.

A. Schedules C9 of Exhibit A-17 calculate two K&M items related to account 880 Distribution Operations Other Expenses.

The first item is associated with new service line installation timeline requirement as required by MPSC Case No. U-20608, Rule 460.2371(7). MGUC is required to install 90% of new service lines within 15 days of receipt or an agreed upon schedule with the customer. The ability to comply with this rule requires adding additional staff to act as inspectors for contractor crews that generally handle this work for MGUC. The Company estimates a K&M increase of \$157,248 for the 2022 test year for this first item.

The second item is associated with Maintenance of Facilities. There are locations within MGUC where maintenance of parking lots, building painting, tuck pointing of buildings, etc. is needed. The Company estimates a K&M increase of \$80,000 for the 2022 test year for this second item.

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1 **Q. Please explain Schedules C10 of Exhibit A-17.**

2 A. Schedules C10 of Exhibit A-17 calculate the K&M adjustment associated with Maintenance of
3 Exposed Main Under Bridges. 49 CFR Part 192 requires inspection and maintenance of main
4 exposed on bridges and to protect against corrosion. MGUC has embarked on a project to replace
5 many mains located on bridges as it is often more advantageous to replace these installations and
6 eliminate the exposed main rather than rewrap the existing main. There have been, however, some
7 locations identified that do not favor replacement due to difficult conditions such as rock and soil
8 contamination. The wrapping of those remaining requires specialized equipment and personnel.
9 The Company estimates a K&M increase of \$100,000 for the 2022 test year.

10 **Q. Please explain Schedules C11 of Exhibit A-17.**

11 A. Schedules C11 of Exhibit A-17 relate to two known and measurable adjustments for account 889,
12 Distribution Maintenance of Measuring and Regulating Station Equipment – General.
13 The first item is associated with station heater maintenance. It was initially determined that the
14 maintenance costs of maintaining MGUC's existing line heaters were greater than the value of the
15 existing line heaters. Therefore, MGUC has been engaged in a heater replacement program over
16 the last 10 years. Required maintenance of the new heaters is on an approximately 10-year cycle.
17 This work is scheduled to begin with the first of the replaced heaters in 2022 (which were installed
18 in 2011). The Company estimates a K&M increase of \$200,000 for the 2022 test year.
19 The second item is associated with Painting of Structures and Stations. MGUC maintains the
20 painting of these structures and stations by brush painting during the annual inspections. As part
21 of the normal maintenance schedule, the regulator structures and stations should also periodically
22 be sandblasted and painted by a professional painter. The Company estimates a K&M increase of
23 \$250,000 for the 2022 test year (\$187,500 for the structures and \$62,500 for the stations).

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1 **Q. Please explain Schedules C12 of Exhibit A-17.**

2 A. Schedules C12 of Exhibit A-17 calculate the K&M adjustment associated with Cross Bores. In
3 response to MPSC issued non-compliance letter NC-365527, the Company will implement a plan
4 to begin performing camera inspections of customer sewer lines to ensure that there are no conflicts
5 with the Company's facilities. This plan would entail inspections of one-half of the Company's
6 service lines over a 25-year period. The K&M increase is calculated as follows: inspect 85,000
7 sewer lines over a 25-year period, or 3,400 sewer line inspections per year at an estimated cost per
8 inspection of \$200. The Company estimates a Known and Measurable increase of \$680,000 (3,400
9 inspections x \$200 per inspection = \$680,000) for the 2022 test year.

10 **Q. Please explain Schedules C13 of Exhibit A-17.**

11 A. Schedules C13 of Exhibit A-17 relate to three known and measurable adjustments for Account 893
12 Distribution Maintenance of Meters and House Regulators.

13 The first item is the K&M adjustment associated with Atmospheric Corrosion Surveys.
14 Historically, atmospheric corrosion surveys had been conducted by meter readers as part of the
15 meter reading process. There is a separate K&M cost reduction related to the elimination of the
16 meter reader positions. The Company plans to have annual atmospheric corrosion survey work
17 done through contract summer employees at a cost of approximately \$30 per hour for 80 days per
18 year in each of the Company's five operating districts. The Company estimates a K&M increase
19 of \$96,000 for the 2022 test year.

20 The second item is the K&M adjustment associated with Painting of Meters identified during
21 atmospheric corrosion survey. As recommended by the MPSC during the Headquarters Inspection
22 on February 1, 2016, MGUC was to capture and correct not only meters with atmospheric corrosion
23 but also those that were in need of paint without atmospheric corrosion. The Company estimates
24 a K&M increase of \$50,000 for the 2022 test year.

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1 The third item is associated with Painting of Large Meter sets. MGUC maintains the painting of
2 these meters by brush painting on an as needed basis. As part of the normal maintenance schedule,
3 and to extend the life of these larger meter sets, they are also periodically sandblasted and painted
4 by a professional painter. The Company estimates a K&M increase of \$112,000 for the 2022 test
5 year.

6 **Q. Please explain Schedules C14 of Exhibit A-17.**

7 A. Schedules C14 of Exhibit A-17 calculate the K&M adjustment associated with AMI system
8 implementation. With the full implementation of AMI, the Company will have eliminated all meter
9 reader positions; significant O&M savings will be the result. The Company will retain five
10 employees to perform maintenance on the AMI units and to perform manual reads as necessary.
11 The Company estimates a K&M decrease of \$1,487,030 for the 2022 test year.

12 **Q. Please explain Schedules C15 of Exhibit A-17.**

13 A. Schedules C15 of Exhibit A-17 calculate the K&M adjustment associated with Real-time Reporting
14 of Damages. MGUC is the only natural gas utility in Michigan that does not report damages in
15 real-time. This is an estimated cost for programing changes and training at Faneuil or to develop
16 the process in house. If an in-house program were developed, MGUC would incur costs for site
17 visits by supervisory personnel during the MPSC's presence and for increased correspondence with
18 the MPSC related to reporting damages to them. The Company estimates a K&M increase of
19 \$20,000 for the 2022 test year.

20 **Q. Please explain Schedules C16 of Exhibit A-17.**

21 A. Schedules C16 of Exhibit A-17, page 1 of 2 calculates the K&M adjustment associated with
22 uncollectibles expense. To be consistent with past practice, MGUC has forecasted its 2022

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1 projected test year uncollectibles expense equal to its 5-year historic average, which is
2 \$1.91 million. This results in a total K&M increase of \$0.27 million in Account 904.

3 Schedules C16 of Exhibit A-17, page 2 of 2, calculates the 2022 projected test year uncollectibles
4 expense of \$1.91 million. As shown on this exhibit, for the 5-year period 2015-2019, MGUC's
5 average net uncollectibles have equaled 1.36% of MGUC's tariff revenues. This percent was
6 multiplied by MGUC's 2022 projected test year revenues of \$141.03 million to arrive at a 2022
7 projected test year uncollectibles expense of \$1.91 million.

8 **Q. Please explain Schedules C17 of Exhibit A-17.**

9 A. Schedules C17 of Exhibit A-17 calculate the K&M adjustment associated with Injuries and
10 Damages. MGUC has forecasted its 2022 projected test year injuries and damages expense to be
11 equal to its 5-year historic average, which is \$586,042 as shown on line 15. That is a K&M increase
12 of \$66,501 over the inflated 2019 costs inflated to 2022.

13 **Q. Please explain Schedules C18 of Exhibit A-17.**

14 A. Schedules C18 of Exhibit A-17 calculate the Benefits K&M expenses for MGUC. MGUC is
15 forecasting a K&M increase of \$0.5 million in Account 926, as shown on Line 22.

16 The 2022 MGUC forecast of employee benefit costs was developed utilizing three forecasting
17 methods depending on the benefit being forecasted. The three methods are: MGUC estimate,
18 inflationary, and actuarial analysis.

19 Lines 1-3 used the MGUC estimate method. Self-insured medical costs, dental costs and 401(k)
20 costs for active employees were determined by calculating a cost per FTE. The rate per 2019 FTE
21 was then applied to the number of FTE's in the test year and inflated as follows:

- 22 • Medical costs: 6.8% for 2020 through 2022, provided by Fidelity
- 23 • Dental costs: 2.5% for 2020 through 2022, provided by Delta Dental

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• 401(k) benefit costs: general wage inflation factors of 2.53% for 2020, 2.80% for 2021 and 2.98% for 2022 were applied

2019 actual costs were inflated by the factors developed in Schedules C20 of Exhibit A-17 for the sub-accounts on lines 6 through 12.

The 2022 employee benefit costs for the sub-accounts on lines 14 through 17 were determined by actuarial analysis.

WBS employee benefit cost projections relied on the same assumptions, actuarial analysis, and methodologies used for MGUC employee benefit costs, as described above. WBS total benefit costs and MGUC's share are calculated on page 2, MGUC's share is included on line 4 on page 1.

Q. Please explain Schedules C19 of Exhibit A-17.

A. Schedules C19 of Exhibit A-17, page 1 of 2, calculates the K&M adjustment associated with Account 930.2. MGUC has forecasted the projected test year Account 930.2 to be \$1.137 million. That is a K&M decrease of \$26,309 from the 2019 costs inflated to 2022. This K&M adjustment is associated with MGUC's portion of the return on and of ("Return On/Of") WBS assets and net working capital as allowed in the shared service agreement between MGUC and WBS. The forecasted 2022 Service Company (WBS) Return On/Of is \$412,915. The 2019 actual amount was \$412,844. The K&M reduction of \$26,309 largely represents the difference between the 2019 amount inflated using the inflation factors shown in Schedules C20 of Exhibit A-17 and the forecasted 2022 Service Company (WBS) Return On/Of amount.

Schedules C19 of Exhibit A-17, page 2, calculates the 2022 Service Company (WBS) Return On/Of, which is a combination of Return on Assets and a Depreciation Charge to MGUC from the Service Company.

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Depreciation Rates

Q. What depreciation rates were used in this rate case?

A. MGUC used its depreciation rates and practices approved in the Commission's August 28, 2018 Order in Case No. U-18488 to determine its 2022 revenue requirement in this rate case. Further details on depreciation can be found at FR-084.

OVERVIEW OF INCENTIVE COMPENSATION

Incentive Compensation Overview

Q. Please describe MGUC's compensation philosophy.

A. Like most customer-focused businesses, MGUC maintains market-based compensation programs so it can attract and retain a qualified and motivated work force. In order for MGUC to provide the highest level of safe and reliable service to its customers, MGUC must be able to attract, retain, and motivate the talented employees who make it possible to achieve excellent overall utility operations. We compete for quality employees in a market that includes regulated and non-regulated energy companies as well as non-energy firms. MGUC's goal, therefore, is to pay its employees a total cash compensation package designed to bring its employees' total cash compensation to the market median (i.e., 50th percentile) of total cash compensation paid to similarly-situated employees at comparable energy industry and general industry (non-energy) companies. The market median levels are primarily based on data provided by Willis Towers Watson, an internationally recognized firm that specializes in both compensation and benefits consulting services.

MGUC's market-median total cash compensation package is comprised of both a base salary and an annual incentive target "pay at risk" component that depends upon certain operational

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1 performance goals being met. In other words, receiving MGUC's base pay alone without a payout
2 from its incentive plans would result in MGUC's employees being paid at a level below the market
3 median, because it is the combination of the base pay target and the annual incentive payout target
4 that brings the total compensation of MGUC's employees to the 50th percentile median of
5 comparable companies. Providing incentive pay at a target amount is not a "bonus" paid to
6 employees over and above market levels, but a critical and expected component of a total
7 compensation level that is set at the market median level.

8 MGUC's compensation programs are reviewed at least annually against the competitive data to
9 ensure its compensation programs will attract and retain a quality work force to serve its customers.
10 MGUC's total cash compensation costs are prudent expenditures that allow MGUC to continue to
11 provide quality service at the level our customers expect while maintaining reasonable rates.

12
13 **Q. What is the importance of including incentive pay as part of MGUC's total cash**
14 **compensation package?**

15 A. Incentive compensation is a critical component of total compensation. According to research from
16 WorldatWork, a global nonprofit organization of compensation professionals, virtually all of the
17 companies with which MGUC competes for quality employees have moved a portion of their total
18 cash compensation to variable pay through annual incentive programs, also known as "pay at risk."
19 For example, the 2018 Incentives and Pay Practices For Publicly-Traded Companies" survey
20 performed by WorldatWork and Deloitte found that 98.5% of organizations use some form of
21 variable pay plan. WorldatWork's 2020-2021 Salary Budget Survey report (August, 2020) found
22 that in 2019 and 2020 84% of organizations offer some sort of variable pay and that the median
23 percentage of employees eligible to receive variable pay in 2019 was 100%. (pp. 42 & 43)
24 MGUC's "pay at risk" structure is an expected component of a total cash compensation package in
25 today's talent marketplace.

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1 Consequently, if MGUC offered only base pay plans without an incentive compensation pay at risk
2 component, it would make it more difficult for MGUC to attract and retain the quality employees
3 required to provide the level of service that its customers demand. Quality employees expect and
4 demand this type of incentive compensation to recognize superior performance given the
5 prevalence of “pay at risk” plans in the marketplace as demonstrated by the information discussed
6 above. If MGUC went to a more fixed-expense basis for compensation in the form of increased
7 base salaries, it would, without any benefit to the customer, put MGUC at a disadvantage in a
8 market where incentive pay programs are prevalent, and would negatively impact MGUC’s ability
9 to attract and retain the quality workforce needed to deliver high levels of customer service.

10
11 **Q. Is there any other reason why it is important for MGUC to include a “pay at risk”**
12 **component in its total cash compensation package?**

13 A. Yes. Including annual incentive plans in its compensation program enables MGUC to offer
14 competitive compensation packages that incentivize employees to improve service levels and
15 reduce costs that impact the rates paid by customers. The incentive plan design focuses employees
16 on key goals and objectives that benefit our customers, as its design measures criteria concentrated
17 on cost containment and operational goals that are aligned with the interests of customers rather
18 than financial measures that might be more aligned with the interests of shareholders. By making
19 a portion of its total cash compensation “at risk”, MGUC is strengthening the link between pay and
20 performance for its employees, thereby increasing MGUC’s ability to engage and compensate its
21 employees for superior performance. Indeed, MGUC’s incentive plans are designed to incentivize
22 employees to improve service levels and reduce costs that impact rates so as to directly benefit
23 MGUC’s customers. If MGUC were to eliminate incentive compensation and use only base pay
24 to compensate its employees at market-median levels, this could reduce the efficiencies that result
25 from MGUC’s ability to engage and incentivize employee accomplishments toward objectives that

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benefit customers: improved safety, customer satisfaction, and cost control. Moving incentive pay to base pay could also reduce MGUC's ability to motivate its employees towards further improvements in these areas, thereby denying customers the benefits they would receive from such improvements.

Q. Does a utility's ability to attract and retain a sufficient, qualified, and motivated work force benefit customers?

A. Yes. Attracting and retaining a sufficient, qualified, and motivated work force directly benefits customers, because it ensures there are enough highly proficient employees to perform needed customer work. In addition, customers benefit by MGUC maintaining and improving the productivity and quality of work performed, which reduces overall costs to customers. By retaining trained and experienced employees through a market-competitive compensation program, MGUC is able to avoid incurring the costs of hiring and training employees to replace workers who otherwise would choose to leave MGUC if such a market-competitive program were not in place. Experienced employees who are familiar with MGUC systems and equipment are more efficient in their performance, further reducing MGUC's operating and maintenance expenses and capital expenditures.

WEC's 2022 Incentive Compensation Plans

Q. What incentive compensation plans will apply to MGUC in the 2022 test year?

A. While the incentive compensation plans for the year 2022 have not been finalized and approved, it is expected that compensation plans essentially identical to MGUC's current plans will remain in place through 2022. There are four different incentive compensation plans applicable to MGUC: (a) the Short-Term Performance Plan ("STPP"); (b) the Omnibus Stock Incentive Plan ("OSIP");

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(c) the Performance Unit Plan (“PUP”), and (d) the Non-Executive Incentive Plan. The first three of these are executive incentive plans.

Executive Incentive Plans

Q. Please give a brief overview of the executive incentive plans.

A. The STPP applies to executive officers of MGUC. It is anticipated that the 2022 plan will apply the same design as the current STPP. For those non-executive officers whose positions primarily relate to utility operations in Michigan, the 2022 annual incentive will apply the same design as the Non-Executive Plan (discussed below).

The OSIP contains two parts that award WEC stock units or stock options to employees based on certain financial criteria. MGUC does not expect the metrics in the 2022 OSIP to differ in relevant part from those contained in the current plan.

The PUP awards WEC performance stock units to employees based on certain financial criteria. MGUC does not expect the criteria to change in relevant part in 2022. This plan is different from the stock unit component of the OSIP in that awards are determined based upon the value of WEC stock and are also contingent on WEC’s total shareholder return relative to an industry comparator group, along with additional performance measure(s) established by the WEC Compensation Committee.

Non-Executive Incentive Plan

Q. Please describe the Non-Executive Incentive Plan.

A. The Non-Executive Incentive Plan sets different annual compensation levels for non-union, non-executive employees based on MGUC’s performance against pre-determined goals in a number of areas that the Company believes are in our customers’ best interests. A copy of the current Non-

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Executive Incentive Plan is attached to my testimony as Exhibit A-19. The plan uses four specific performance measures to determine incentive payouts for MGUC employees as well as WBS employees that provide service to MGUC, all of which are focused on operational aspects of the business, including cost management.

The plan does not contain any financial-specific measures that in previous rate cases the Commission has characterized as being of primary benefit to shareholders rather than customers. Instead, MGUC's measures assess cost control applying net income to measure non-fuel O&M expenses, which is weighted at 50% of the total. In addition, employee safety, customer service and supplier and workforce diversity are weighted at a combined 50% of the total. The plan design is as follows:

Operational Performance Measure	Description	Weighting
Cost Management Net Income	Assess cost management via non-fuel Net Income, to help maintain or reduce expenses that may be charged to customers in future rate cases.	50%
Employee Safety	Employee safety is measured under two plan components: (1) OSHA recordable incidents and (2) Lost-Time Injuries. Each component is weighted equally. Performance is measured based on an annual improvement target for MGUC.	15%
Customer Satisfaction	Performance for customer satisfaction is determined by two measures: (1) Overall Satisfaction with Transactions and (2) Overall Satisfaction with MGUC. Each measure is weighted equally. The results for each of these measures are calculated by weighting the average results across the following transactions: Appointments, Billing, Care Center, Gas Emergencies, and Move Orders.	30%
Diversity	Diversity is a two-part, equally-weighted measure. Supplier diversity is based on the amount of spending against predetermined targets with qualified minority-, women-, service-disabled-, and veteran-owned businesses. Workforce diversity is based on evaluation against an agreed set of criteria including recruitment, promotion, and retention.	5%

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Q. What is the focus of these operational measures?

A. Our operational measures are focused on improving the quality of services delivered to customers, including cost control of expenses that impact rates. The measures are designed to motivate employees to maintain customer support at a high-quality level and at competitive rates.

Q. Who participates in the Non-Executive Incentive Plan?

A. Participants include non-union, non-executive employees of MGUC, as well as employees of WBS that provide support to MGUC. A portion of the non-executive incentive compensation costs for WBS employees incurred under the Non-Executive Incentive Plan is allocated to MGUC.

Q. Why is the current Non-Executive Incentive Pay Plan, attached as Exhibit A-19, relevant for the present rate case with a 2022 test year?

A. WEC approves its non-executive incentive compensation plans on an annual basis, establishing the metrics applicable to each of its utility affiliates and the targets to be met by those utility affiliates in order to earn payouts based on their performance during that year. If a utility’s performance in those metrics meets or exceeds its targets, payout under the plan occurs the following year. The 2021 Non-Executive Incentive Plan is the plan that governs incentive pay for performance that occurs during calendar year 2021. The payouts under this plan will occur no later than March 15, 2022. See Exhibit A-19, page 1, for MGUC and Page 2 for WBS (confidential and public versions). The 2022 plan will be formally adopted in early 2022 and is expected to remain unchanged from 2021. MGUC expects that its non-executive incentive compensation for performance during

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

calendar year 2022 will be governed by a substantially identical plan with the same metrics and weightings.

Q. How does the Cost Management Net Income metric benefit customers?

A. The Cost Management Net Income metric correlates to reductions in Non-Fuel O&M Expenses, benefitting customers by reducing the costs of service that must be recovered from customers in future rate cases. This metric encourages employees to maintain or reduce operational costs at or below the target level set for MGUC. The more O&M costs are reduced, the higher the resulting net income and associated payout for which employees may be eligible. This metric benefits customers because all else being equal, increased income via lowered expenses will reduce the amount of costs to be recovered in future rate cases.

To the extent any cost savings are permanent, the result will be lower rates for MGUC customers for years to come.

Q. Is there evidence that the Cost Management Net Income metric has worked to control or reduce MGUC's costs so as to benefit customers?

A. Yes. The Company's recent performance demonstrates that the Net Income cost control metric successfully incentivizes both utilities' employees to control operating expenses. The Company's performance for the most recent three years for which we have data is as follows:

- 2018 – Based on the 2018 incentive plan, the Company's goal was to achieve a 2018 net income of \$10.9 million. The Company beat that goal by \$5.8 million, which resulted from reducing Total 2018 Non-fuel O&M Expense by an equivalent amount.

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

- 1 • 2019 – Based on the 2019 incentive plan, the Company’s goal was to achieve a 2019 net income
2 level of \$12.2 million. The Company beat that goal by \$6.1 million, which resulted from
3 reducing Total 2019 Non-fuel O&M Expense by an equivalent amount.
- 4 • 2020 – Based on the 2020 incentive plan, the Company’s goal was to achieve a 2020 net income
5 of \$13.7 million. The Company beat that goal by \$400 thousand, which resulted from reducing
6 Total 2020 Non-fuel O&M Expense by an equivalent amount.

7 In the absence of the cost control metric, MGUCs Non-Fuel O&M Expense from 2018 to present
8 likely would have been higher than MGUC was able to achieve with that metric in place. Moreover,
9 the O&M costs budgeted for the 2022 test year at issue in this rate case likely would have been
10 higher in the absence of the Non-Executive Incentive Plan’s cost control and reduction metric.
11 When costs are reduced or controlled in one year, that reduction or control carries through to the
12 basis used in planning the following years’ budgets.

13
14 **Q. Is recovery for the costs of the O&M cost control metric in this rate case consistent with and**
15 **supported by the ratemaking treatment of such costs in prior rate cases of other utilities?**

16 A. Yes. Recovery for the costs of the O&M cost control metric in this rate case would be consistent
17 with and supported by the regulatory treatment of incentive compensation plan metrics that are
18 designed to control or reduce O&M costs. In *Consumers Illinois Water Company*, Docket No. 03-
19 0403 (Order at 14–15), a case often cited by the Illinois Commerce Commission (“ICC”) as
20 establishing the standard for recovery of incentive compensation costs, the ICC approved the
21 recovery of Consumers Illinois Water Company’s incentive compensation expenses, which
22 included a metric for “maintaining or reducing operating costs at or below budgeted levels.”

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 **Q. Is it your opinion that the Commission should allow MGUC to recover the costs associated**
2 **with the cost control metric for the 2022 test year in this rate case?**

3 A. Yes. Based on the specific evidence presented as to how the O&M cost control metric in the Non-
4 Executive Incentive Plan benefits customers and the Commission’s long-standing treatment of
5 costs associated with such metrics, the Commission should approve the recovery of MGUC’s costs
6 associated with the plan’s O&M cost control metric in this proceeding.

7
8 **Q. How does the Employee Safety metric benefit customers?**

9 A. The Employee Safety metric benefits customers by reducing costs and inefficiencies associated
10 with on-the-job accidents. The focus on employee safety is part of a larger effort to create a “Safety
11 Culture” in which all aspects of safety – public safety, customer safety, and employee safety –
12 become a daily part of what we do. By reviewing OSHA-recordable incidents and Lost Time
13 Injuries, MGUC is able to identify the frequency and severity of injuries and illnesses impacting
14 employees at each company and across the organization. Moreover, safer employees are more
15 motivated and efficient than those who operate in a less safe environment. Thus, by encouraging
16 increased safety for employees, this metric leads to more efficiency and lower costs, which are
17 direct benefits to customers.

18
19 **Q. How does the Customer Satisfaction metric benefit customers?**

20 A. The Customer Satisfaction metric benefits customers by encouraging MGUC employees to
21 improve MGUC’s performance in all of its interactions with customers—appointments, billing,
22 care center, move/transfer service, and gas emergencies. Customers are surveyed as to their
23 satisfaction when they have one of these key transactions with the utility. The plan metric is based

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

on the proportion of customers who are “very satisfied” (rating 8, 9 or 10 on a 10-point scale). Results are tracked on an annual basis. MGUC’s customers benefit from this metric because it helps ensure that they continue to receive high-quality service from MGUC employees and encourages further improvements in that service quality.

Q. How does the Diversity metric benefit customers?

A. Our customers represent a diverse population. To the degree that our workforce and our suppliers mirror that diversity, we can benefit our customers through a highly productive and engaged workforce. Our commitment to diversity promotes innovation, demonstrates MGUC’s commitment to and support of the economic and business growth of the communities we serve, and supports and cultivates our relationships with community leaders, advocacy groups, and external stakeholders.

Q. Do you have any comments concerning the interrelation between the Cost Management Non-fuel O&M Expense metric and the other three metrics in the Non-Executive Incentive Plan?

A. Yes. The Employee Safety, Customer Satisfaction and Diversity metrics demonstrate that the cost control metric’s target is not a one-dimensional goal, intended to be met solely by eliminating costs and neglecting investment in people and programs needed for the long-term sustainability of MGUC’s operations. These metrics demonstrate MGUC’s emphasis on providing safe and reliable gas distribution service to its customers, and the cost control metric demonstrates MGUC’s emphasis on managing its operations to achieve these service goals in an efficient and cost-effective manner. In this way, the four metrics work together to encourage MGUC’s non-executive employees to improve safety, reliability and service to customers, but in an efficient and non-

DIRECT TESTIMONY AND EXHIBITS OF
JOSEPH L. ZGONC

1 wasteful manner. The result is that customers receive the benefits of both improved safety,
2 reliability and service and the costs they pay for that service being controlled or reduced.

3
4 **Q. Do you propose that MGUC recover, in rates, the costs of the Non-Executive Incentive Plan**
5 **in their entirety?**

6 A. Yes, for the reasons stated above.

7 **Matching of Gas Costs and Gas Cost Revenues**

8 **Q. Has MGUC matched gas costs and gas cost revenues in the calculation of the revenue**
9 **deficiency in this general rate case proceeding?**

10 A. Yes. The gas cost recovery factors used to calculate Revenues on Present Rates in this general rate
11 case proceeding were calculated, such that gas costs equaled gas cost revenues, resulting in one-
12 for-one recovery of gas costs.

13 **Q. Does this conclude your pre-filed direct testimony at this time?**

14 A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

DIRECT TESTIMONY AND EXHIBITS OF

JARED J. PECCARELLI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

QUALIFICATIONS
OF
JARED J. PECCARELLI
PART I

1 **Q. Please state your name, position and business address.**

2 A. My name is Jared J. Peccarelli. My business address is 231 West Michigan St.,
3 Milwaukee, WI 53203. I am employed by WEC Business Services, LLC (“WBS”), a
4 subsidiary of WEC Energy Group, Inc. (“WEC”), as Manager - Sales Forecasting

5

6 **Q. For whom are you providing testimony?**

7 A. I am providing testimony on behalf of Michigan Gas Utilities Corporation (“MGUC”
8 or the “Company”), a subsidiary of WEC.

9

10 **Q. Please describe briefly your educational, professional, and utility background**

11 A. I received both a Bachelor of Science degree in Computer Science and a Master of
12 Business Administration degree with a finance concentration from the University of
13 Wisconsin – Milwaukee. In addition, I have completed all coursework required for a
14 Master of Science degree in Applied Economics from Marquette University in

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 Milwaukee, Wisconsin. I was hired by We Energies (a subsidiary of WEC Energy
2 Group) in November 2002 and worked in various roles in several departments prior to
3 my current position. I joined the Sales Forecasting team in Finance as a Principal
4 Analyst in 2014 and have developed or assisted in the development of long-term
5 electric and natural gas sales forecasts for multiple WEC utility subsidiaries since
6 then. I am currently responsible for overseeing the development of the long-term
7 sales forecasts for all of the electric, natural gas and steam utility subsidiaries of
8 WEC, including MGUC.

9
10 **Q. Have you previously testified before any regulatory agency?**

11 A. Yes. I have submitted testimony concerning sales forecasting on behalf of MGUC's
12 2021-2022 GCR Plan before the Michigan Public Service Commission ("MPSC" or
13 the "Company") in Case No. U-20818 and before the Public Service Commission of
14 Wisconsin and the Illinois Commerce Commission in general rate case proceedings..

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

JARED J. PECCARELLI
DIRECT TESTIMONY
PART II

1 **Q. What is the purpose of your pre-filed direct testimony?**

2 A. The purpose of my direct testimony is to provide an explanation of the methodology
3 used to develop MGUC's weather normalization procedure and sales forecast for the
4 2022 projected test year.

5

6 **Q. Are you sponsoring any exhibits in this proceeding?**

7 A. Yes. I am sponsoring the following exhibits:

8	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
9	A-5	E1	Annual Service Sales by Major Customer
10			Classes and System Output 5-Year Historical;
11	A-15	E1	Market Outlook: 5-Year Annual Calendar
12			Gas Forecast by Class

13 **Q. Were these exhibits prepared by you or under your direction?**

14 A. Yes, they were.

15

16 **Q. Please explain Exhibit A-5, Schedule E1.**

17 A. Exhibit A-5, Schedule E1, is a summary of the five-year Historical Annual Service
18 Area Sales by Major Customer Classes and System Output. This exhibit is filed in
19 accordance with the Commission's directive in Case No. U-18238.

20

21

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 **Q. Please explain how the MGUC’s 2022 projected test year sales forecast was**
2 **developed.**

3 A. The sales forecasts for the Residential, Small General Service (“SGS”), Large
4 General Service (“LGS”) and Transportation classes were developed using a
5 combination of three methods.

6 The first method was a multiplicative approach used for the Residential and SGS
7 classes. Regression models were developed in the Itron MetrixND forecasting
8 application to forecast the number of customers and the average use per customer for
9 each class. The total sales for each class were estimated by multiplying the customer
10 forecast by the average use per customer forecast. The regression models used
11 historical monthly data covering the period January 2014 through September 2020.
12 The regression models estimated the relationship between the dependent variables
13 (e.g., average user per customer, number of customers) and independent variables
14 such as economic, demographic, weather and seasonal factors, and then projected
15 future levels of average use per customer and number of customers.

16
17 Gas Cost Recovery (“GCR”) and Gas Customer Choice (“GCC” or “Choice”)
18 customers were included in the same average use per customer and number of
19 customers models for the Residential and SGS classes. For example, the Residential
20 average use per customer model forecasted total residential usage. The monthly
21 estimates from the average use per customer models were multiplied by the monthly
22 estimates from the number of customers model to forecast total sales for each class.
23 The forecasted sales for each class were then disaggregated into GCR and GCC sales

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 forecasts based on recent historical Choice customer counts. In other words, the
2 number of Choice customers in the forecast horizon was assumed to remain constant.

3

4 The second method was used for the LGS class and entailed two parts. The largest
5 customer in the class was individually forecasted because its usage accounted for
6 more than half of the total class usage. The remaining customers were forecasted as a
7 residual group based on historical trends.

8 The third method was used for the Transportation class which included both
9 Commercial Transportation and Transportation Aggregation customers. These
10 customers were individually forecasted based on input from the customer account
11 managers.

12

13 **Q. Please explain how normal weather was defined.**

14 A. Normal weather was defined as the average of the 15 coldest years in the most recent
15 16-year historical period using heating degree days with a set point of 65 degrees
16 Fahrenheit. This methodology was agreed upon in U-17273. For the 2022 projected
17 test year, the annual total of 6,245 heating degree days was based on the 16-year
18 period of 2004 through 2019 with the warmest year, 2012, removed from the
19 calculation.

20

21 **Q. Please explain the development of the weather data.**

22 A. Actual heating degree days were calculated on a daily basis by subtracting the
23 average daily temperature from the set point of 65 degrees Fahrenheit. The

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 calculation used a floor value of zero which meant that an average daily temperature
2 equal to or greater than 65 degrees resulted in zero heating degree days for the day.
3 Each day's average temperature was calculated by averaging all of the hourly
4 temperature values for the day. The hourly temperatures were provided by DTN, a
5 third-party data, analytics and technology service provider.

6
7 The Company used the weighted average weather data from four weather stations to
8 calculate actual and normal heating degree days:

- 9 1) Benton Harbor, MI: 37.4%
10 2) Monroe, MI: 31.3%
11 3) Coldwater, MI: 15.9%
12 4) Grand Rapids, MI: 15.4%

13
14 The weights were based on the estimated number of customers in proximity to each
15 weather station as a percentage of total company customers. The estimate was based
16 on the number of residential, small general service, and large general service
17 customers as of October 2015. The customers were grouped by zip code and then
18 aggregated to counties in order to be assigned to the geographically closest weather
19 station.

20
21
22 **Q. What is the 2022 Test Year forecast of retail and transportation deliveries?**

23 **A.** The 2022 Test Year forecast of retail and transportation deliveries, excluding

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 company use and losses, is 33,637 MMcf as presented in Exhibit A-15, Schedule E1.
2 System Output in the Test Year is projected to be 33,575 MMcf.

3

4 **Q. How does the 2022 Test Year forecast compare to 2020 weather-normalized**
5 **deliveries?**

6 A. The 2022 Test Year forecast of total deliveries is 2.6% higher than 2020 weather-
7 normalized deliveries. The 2022 Test Year forecast of Residential deliveries is 1.6%
8 higher than 2020 weather-normalized deliveries. Residential deliveries include GCR
9 and GCC customers. The 2022 Test Year forecast of Commercial deliveries is 8.4%
10 higher than 2020 weather-normalized deliveries. Commercial deliveries include SGS
11 GCR, SGS GCC and Commercial Lighting customers. The 2022 Test Year forecast
12 of Industrial deliveries is 1.0% higher than 2020 weather-normalized deliveries.
13 Industrial deliveries include LGS GCR, LGS GCC, Special Contract, and End-Use
14 Transportation customers.

15

16 **Q. How does the 2022 Test Year forecast compare to the 2016 Test Year forecast**
17 **from the Final Order of Case No. U-17880?**

18 A. The 2022 Test Year forecast of total deliveries is 6.5% higher than the 2016 Test
19 Year forecast used to determine rates approved in Case No. U-17880. The 2022 Test
20 Year forecast of Residential deliveries is 1.2% higher than the 2016 Test Year
21 forecast. The 2022 Test Year forecast of Commercial deliveries is 14.8% higher than
22 the 2016 Test Year forecast. The 2022 Test Year forecast of Industrial deliveries is
23 8.3% higher than the 2016 Test Year forecast.

DIRECT TESTIMONY AND EXHIBITS OF
JARED J. PECCARELLI

1 **Q.** **Does this complete your pre-filed direct testimony at this time?**

2 **A.** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY AND EXHIBITS OF
ANN E. BULKLEY
STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

**QUALIFICATIONS
OF
ANN E. BULKLEY
PART 1**

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. Please state your name, occupation, and business address.**

3 A. My name is Ann E. Bulkley. I am employed by Concentric Energy Advisors, Inc.
4 ("Concentric") as a Senior Vice President. My business address is 293 Boston Post
5 Road West, Suite 500, Marlborough, Massachusetts 01752.

6 **Q. On whose behalf are you submitting this testimony?**

7 A. I am submitting this direct testimony before the Michigan Public Service
8 Commission ("Commission") on behalf of Michigan Gas Utilities Corporation
9 ("MGUC" or the "Company").

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

1 **Q. Please describe your background and professional experience in the energy**
2 **and utility industries.**

3 A. I hold a Bachelor's degree in Economics and Finance from Simmons College and
4 a Master's degree in Economics from Boston University, with more than 20 years
5 of experience consulting to the energy industry. I have advised numerous energy
6 and utility clients on a wide range of financial and economic issues with primary
7 concentrations in valuation and utility rate matters. Many of these assignments
8 have included the determination of the cost of capital for valuation and ratemaking
9 purposes. I have included my resume and a summary of testimony that I have filed
10 in other proceedings as Attachment A to this testimony.

11 **Q. Please describe Concentric's activities in energy and utility engagements.**

12 A. Concentric provides financial and economic advisory services to many and various
13 energy and utility clients across North America. Our regulatory, economic, and
14 market analysis services include utility ratemaking and regulatory advisory
15 services; energy market assessments; market entry and exit analysis; corporate and
16 business unit strategy development; demand forecasting; resource planning; and
17 energy contract negotiations. Our financial advisory activities include buy- and
18 sell-side merger, acquisition, and divestiture assignments; due diligence and
19 valuation assignments; project and corporate finance services; and transaction
20 support services. In addition, we provide litigation support services on a wide range
21 of financial and economic issues on behalf of clients throughout North America.

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

**ANN E. BULKLEY
DIRECT TESTIMONY
PART II**

1 **II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY**

2 **Q. What is the purpose of your Direct Testimony?**

3 A. The purpose of my Direct Testimony is to present evidence and provide a
4 recommendation regarding the appropriate return on equity (“ROE”)¹ for MGUC,
5 and to assess the reasonableness of its proposed capital structure for ratemaking
6 purposes.

7 **Q. What schedules are you sponsoring?**

8 A. I am sponsoring the following schedules of Exhibit A-14:

<u>Schedule No.</u>	<u>Description</u>
Schedule D6	Summary of Results
Schedule D7	Proxy Group Selection
Schedule D8	Constant Growth DCF Model
Schedule D9	Multi-Stage DCF Model
Schedule D10	Long-term GDP Growth Rate
Schedule D11	Capital Asset Pricing Model / Empirical Capital Asset Pricing Model – Value Line and Bloomberg Beta
Schedule D12	Capital Asset Pricing Model / Empirical Capital Asset Pricing Model – Long-term Average Beta
Schedule D13	Long-term Average Beta
Schedule D14	Market Return
Schedule D15	Bond Yield Plus Risk Premium
Schedule D16	Size Premium Analysis

¹ Throughout my Direct Testimony, I interchangeably use the terms “ROE” and “cost of equity”.

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

Schedule D17 Capital Expenditures Analysis

Schedule D18 Regulatory Risk Analysis

Schedule D19 Flotation Cost

Schedule D20 Capital Structure Analysis

1 **Q. How is the remainder of your testimony organized?**

2 A. Section III provides a summary of my analyses and conclusions. Section IV
3 reviews the regulatory guidelines pertinent to the development of the cost of capital.
4 Section V discusses current and projected capital market conditions and the effect
5 of those conditions on MGUC's cost of equity. Section VI explains my selection
6 of a proxy group of natural gas utilities. Section VII describes my analyses and the
7 analytical basis for the recommendation of the appropriate ROE for MGUC.
8 Section VIII provides a discussion of specific regulatory, business, and financial
9 risks that have a direct bearing on the ROE to be authorized for the Company in
10 this case. Section IX assesses the Company's proposed capital structure as
11 compared to the proxy group. Section X presents my conclusions and
12 recommendations for the market cost of equity.

13 **III. SUMMARY OF ANALYSIS AND CONCLUSIONS**

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

16 A. To develop my ROE recommendation, I first developed a proxy group that consists
17 of natural gas distribution companies that face risks generally comparable to those
18 faced by MGUC. To that natural gas distribution company proxy group, I applied
19 the Constant Growth form of the Discounted Cash Flow ("DCF") model, the Multi-
20 Stage DCF model, the Capital Asset Pricing Model ("CAPM"), the Empirical

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

1 Capital Asset Pricing Model (“ECAPM”), and the Risk Premium approach. As
2 discussed in more detail in Section VII of my Direct Testimony, it is appropriate to
3 rely on several analytical approaches because market conditions affect the
4 assumptions used in each model differently. Therefore, the use of multiple ROE
5 estimation models is beneficial to provide benchmarks and a range of results to
6 consider.

7 **Q. Please summarize the key factors considered in your analyses and upon which**
8 **you base your recommended ROE.**

9 A. In developing my recommended ROE for MGUC, I considered the following:

- 10 • The *Hope* and *Bluefield* decisions² that established the standards for
11 determining a fair and reasonable allowed ROE, including consistency of
12 the allowed return with the returns of other businesses having similar risk,
13 adequacy of the return to provide access to capital and support credit
14 quality, and the requirement that the result lead to just and reasonable rates.
- 15 • The effect of current and projected capital market conditions on investors’
16 return requirements.
- 17 • The results of several analytical approaches that provide estimates of the
18 Company’s cost of equity.
- 19 • The Company’s regulatory, business, and financial risks relative to the
20 proxy group of comparable companies, and the implications of those risks.

² Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

DIRECT TESTIMONY AND EXHIBITS OF
ANN E. BULKLEY

1 **Q. Please explain how you considered those factors.**

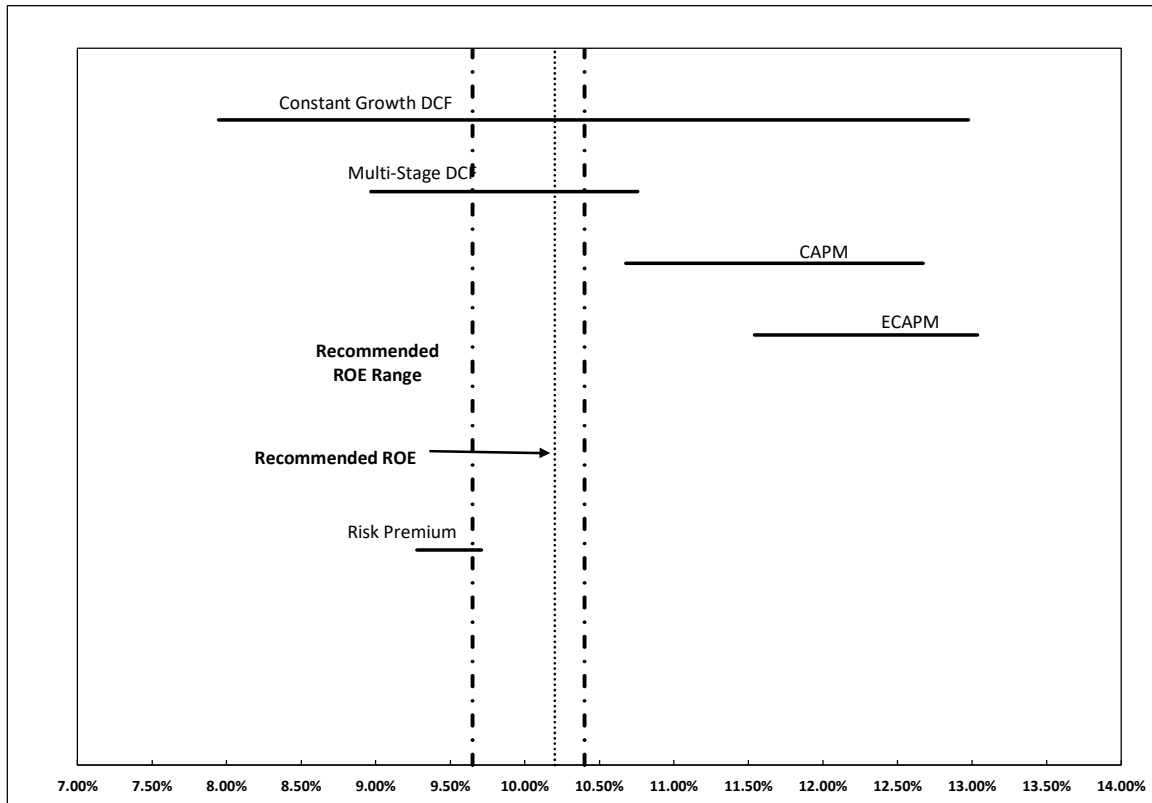
2 A. I relied on several analytical approaches to estimate MGUC's cost of equity based
3 on a proxy group of publicly traded companies. As shown in Figure 1, those ROE
4 estimation models produce a wide range of results. My conclusion about where
5 within that range of results MGUC's ROE falls is based on the Company's business
6 and financial risk relative to the proxy group. Although the companies in my proxy
7 groups are generally comparable to MGUC, each company is unique, and no two
8 companies have the exact business and financial risk profiles. Accordingly, I
9 selected proxy groups with similar, but not the same risk profiles; and I adjusted
10 the results of my analysis either upwards or downwards within the reasonable range
11 of results to account for any residual differences in risk.

12 **Q. Please summarize the results of the ROE estimation models that you**
13 **considered to establish the range of ROEs for MGUC.**

14 A. Figure 1 summarizes the range of results produced by the Constant Growth DCF,
15 Multi-Stage DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analysis.

DIRECT TESTIMONY AND EXHIBITS OF
ANN E. BULKLEY

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1 (and in Schedule D6), the range of results produced by the ROE estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide in order to appropriately consider the factors that have resulted in the diverging range of results.

As a result, my ROE recommendation considers the results of the DCF model, forward looking CAPM and ECAPM analyses, and Risk Premium analysis. I also consider company-specific risk factors and current and prospective capital market conditions.

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

1 **Q. What is your recommended ROE for MGUC?**

2 A. Considering the analytical results presented in Figure 1, as well as the level of
3 regulatory, business, and financial risk faced by MGUC's natural gas operations
4 relative to the proxy group, I believe a range from 9.65 to 10.40 percent is
5 reasonable. This recommendation reflects the range of results for the proxy group
6 companies, the relative risk of MGUC as compared to the proxy group, and current
7 capital market conditions. Within that range, a return of 10.20 percent is
8 reasonable.

9 **Q. What is your recommendation regarding MGUC's requested capital**
10 **structure?**

11 A. As detailed in Section IX of my Direct Testimony, I find that MGUC's proposed
12 52.50 percent common equity is reasonable, given that it is well within the range
13 of equity ratios for the utility operating subsidiaries of the proxy group companies.

14 **IV. REGULATORY GUIDELINES**

15 **Q. Please describe the principles that guide the establishment of the authorized**
16 **ROE for a regulated utility.**

17 A. The United States Supreme Court's *Hope* and *Bluefield* decisions established the
18 standards for determining the fairness or reasonableness of a utility's authorized
19 ROE. Among the standards established by the Court in those cases are: (1)
20 consistency with other businesses having similar or comparable risks; (2) adequacy
21 of the return to support credit quality and access to capital; and (3) the principle

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

1 that the specific means of arriving at a fair return are not important, only that the
2 end result leads to just and reasonable rates.³

3 **Q. Has the Commission provided similar guidance in establishing the appropriate**
4 **return on common equity?**

5 A. Yes, it has. In Case No. U-20697 for Consumers Energy Company (“Consumers”),
6 the Commission stated that:

7 The criteria for establishing a fair rate of return for public
8 utilities is rooted in the language of the landmark United States
9 Supreme Court cases *Bluefield Waterworks & Improvement*
10 *Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S
11 Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v*
12 *Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333
13 (1944). The Supreme Court has made clear that, in
14 establishing a fair rate of return, consideration should be given
15 to both investors and customers. As stated on page 12 of the
16 December 23, 2008 order in U-15244 (December 23 order),
17 “the rate of return should not be so high as to place an
18 unnecessary burden on ratepayers, yet should be high enough
19 to ensure investor confidence in the financial soundness of the
20 enterprise.” Nevertheless, the Commission observes that the
21 determination of what is fair or reasonable, “is not subject to
22 mathematical computation with scientific exactitude but
23 depends upon a comprehensive examination of all factors
24 involved, having in mind the objective sought to be attained in
25 its use.” *Meridian Twp v City of East Lansing*, 342 Mich 734,
26 749; 71 NW2d 234 (1955).⁴

27 This guidance is in accordance with my view that an authorized rate of return on
28 equity must be sufficient to enable regulated companies, like MGUC, the ability to
29 attract equity capital on reasonable terms.

³ *Bluefield Water Works Co. v. Public Serv. Comm’n* 262 U.S. 679, 692-93; *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 603.

⁴ Michigan Public Service Commission Order, Consumers Energy Company, Case No. U-20697, December 17, 2020, at 156.

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1 **Q. How is a company's cost of equity determined?**

2 A. A company's cost of equity ("COE") equals the ROE the market *requires* in order
3 to justify providing capital to that company. In my Direct Testimony, I use the
4 terms "COE" and "market-required ROE" interchangeably. The COE is estimated
5 using multiple analytical techniques that rely on market-based data to quantify
6 investor expectations. Quantitative models produce a range of results from which
7 practitioners select an estimate of the COE—and then adjust and refine that
8 estimate to reflect certain incremental costs and risks. That selection must be based
9 on a comprehensive review of relevant data and information and does not
10 necessarily lend itself to a strict mathematical solution. In estimating a company's
11 COE, it is critical to ensure that the methodologies employed reasonably reflect
12 investors' views of the financial markets, of the proxy group, and of the subject
13 company.

14 **Q. Why is it important that a utility be allowed the opportunity to earn an ROE**
15 **that is, at least, equal to its COE?**

16 A. An authorized ROE that is comparable to MGUC's COE will enable the Company
17 to attract equity capital on reasonable terms—and, accordingly, to continue
18 providing safe, reliable natural gas service while maintaining its financial integrity.
19 To the extent the Company is allowed the opportunity to realize equity returns that
20 are comparable to the investor-required return on equity, neither customers nor
21 shareholders are disadvantaged.

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1 **Q. Is a utility’s ability to attract equity capital affected by the ROEs that are**
2 **authorized for other utilities?**

3 A. Yes, it is. Utilities compete with other investments of similar risk for equity capital
4 from the market. The ROE awarded to a utility sends an important signal to
5 investors regarding whether there is regulatory support for financial integrity,
6 dividends, growth, and fair compensation for business and financial risk. A
7 company’s COE is defined by, and equal to, the opportunity cost of investing in
8 that company. In other words, if higher returns are available from other investments
9 of comparable risk, investors have an incentive to direct their capital to those
10 investments. In such case, equity capital becomes more scarce—and thus more
11 expensive—to the company in question. Thus, the ROE that is authorized to a
12 utility *affects* a utility’s realized COE. With respect to MGUC, this means that an
13 authorized ROE significantly below ROEs authorized for other natural gas utilities
14 could inhibit its ability to attract capital on reasonable terms for investment in
15 Michigan.

16 **Q. Does the fact that the Company is owned by WEC Energy Group (“WEC”), a**
17 **publicly-traded company, affect your analysis?**

18 A. No, it does not. In this proceeding, consistent with stand-alone ratemaking
19 principles, it is appropriate to establish the cost of equity for MGUC, not its
20 publicly-traded parent WEC. More importantly however, it is important to
21 establish a return on equity and capital structure that provide MGUC the ability to
22 attract capital on reasonable terms, on a stand-alone basis, and within the WEC
23 system. All the utility operating subsidiaries within the WEC corporate structure

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1 compete for discretionary capital. Unless MGUC is provided a reasonable
2 opportunity to earn a market-based ROE with an appropriate capital structure, it
3 will be at a disadvantage in attracting discretionary capital from parent company
4 resources.

5 **Q. What are your conclusions regarding regulatory guidelines?**

6 A. The ratemaking process is premised on the principle that, in order for investors to
7 commit the capital needed to provide safe and reliable utility services, a utility must
8 have the opportunity to earn the return *of* its invested capital and also the market-
9 required return *on* its invested capital. Because utility operations are capital-
10 intensive, it is particularly important that regulatory decisions enable the utility to
11 attract capital on reasonable terms. Doing so balances the long-term interests of
12 the utility and its customers.

13 The financial community carefully monitors the current and expected financial
14 condition of utility companies and the regulatory framework in which they operate.
15 In that respect, the regulatory framework is one of the most important factors in
16 both debt and equity investors' assessments of risk. Therefore, the Commission's
17 order in this case should establish rates that provide MGUC with the opportunity to
18 earn an ROE that is: (1) adequate to attract capital on reasonable terms; (2)
19 sufficient to ensure its financial integrity; and (3) commensurate with returns
20 available from enterprises with similar risk. To the extent the Company is
21 authorized to earn an ROE at least equal to its actual COE, the proper balance is
22 achieved between customers' and shareholders' interests.

23

1 **V. CAPITAL MARKET CONDITIONS**

2 **Q. How do capital market conditions affect ROE estimation models?**

3 A. ROE estimation models rely on market data that describe the proxy group
4 companies in the case of the DCF model and CAPM and overall market risk, in the
5 case of the CAPM and Bond Yield Plus Risk Premium model. Therefore, ROE
6 estimation model results are affected by the market conditions prevailing at the time
7 the analysis is performed. If investors do not consider those prevailing market
8 conditions to be sustained throughout the rate period, then it is possible that the
9 ROE estimation models based solely on *current* market data will not provide an
10 accurate estimate of investors' required return during the rate period. Therefore, it
11 is very important to consider *projected* market data to estimate the return for that
12 future period.

13 **Q. How is the current capital market affecting the COE of regulated utilities?**

14 A. The cost of equity of regulated utility companies is currently being affected by three
15 key factors in the capital market: (1) elevated market volatility due to the economic
16 effects of the COVID-19 pandemic; (2) as the economy recovers from the COVID-
17 19 recession, investors are expected to rotate into cyclical sectors; thus utilities, a
18 defensive sector, are expected to underperform the market over the near-term; and
19 (3) the continued effects of 2017 federal tax policy changes on utility cash flows.
20 In this section of my Direct Testimony, I discuss each of these factors and how it
21 affects ROE estimation models.

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1 **Current Market Conditions and Effect on Valuations**

2 **Q. Please summarize current market conditions.**

3 A. In 2020, market conditions were extremely volatile. In January and early February
4 2020, many major market indices reached new threshold levels. As the gravity of
5 the global health pandemic became more apparent, the market became increasingly
6 volatile: in mid-February, utility stock prices reached an all-time high, followed by
7 a significant decline in the overall market and utility stocks; and in March, the S&P
8 500 Index swung by more than three percent on 16 of the 22 trading days. While
9 volatility has declined from the levels in March, there is still much uncertainty in
10 financial markets as a result COVID-19. In the January meeting the Federal
11 Reserve Open Market Committee (“FOMC”) recognized the uncertainty related to
12 the course of the pandemic which will weigh on economy activity and pose risks to
13 the economic outlook.⁵

14 **Q. Have you reviewed any indicators that measure volatility in the financial**
15 **markets?**

16 A. Yes, I reviewed a measure of volatility in financial markets, the Chicago Board
17 Options Exchange (“CBOE”) Volatility Index (“VIX”). The VIX measures
18 investors’ expectation of volatility in the S&P 500 over the next 30 days. As shown
19 in Figure 2, the VIX has recently reached levels not seen since the Great Recession
20 of 2008-2009.

⁵ FOMC, Press Release, January 27, 2021, at 1.

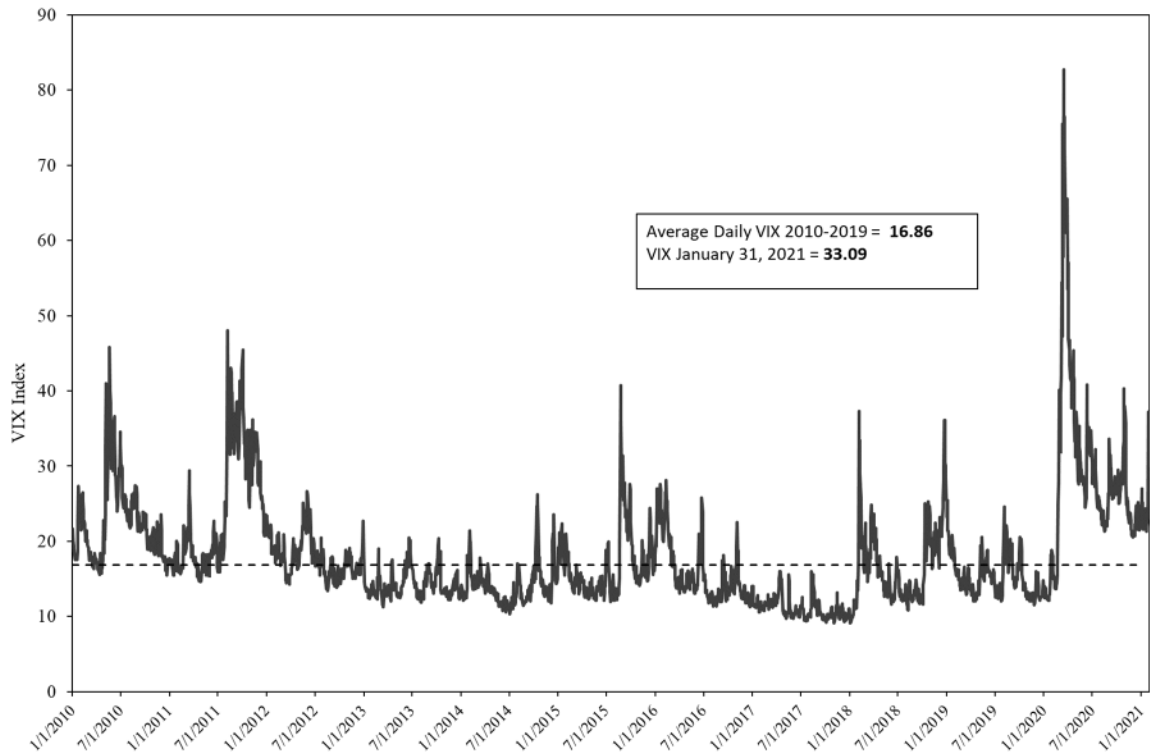
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1 Furth
2 ermore, as shown in Figure 2, while the VIX has declined between April 2020 and
3 January 2021, this measure of volatility still remains well above levels seen prior
4 to COVID-19 in January and February 2020, averaging 16.40 during that period,
5 versus 30.94 for the period of March 2020 through January 2021. It is important to
6 view the declines in the VIX in the context of the unprecedented response by the
7 Federal Reserve and Congress. As discussed in more detail below, the Federal
8 Reserve's corporate bond buying programs are providing liquidity to bond markets
9 and therefore reducing some of the uncertainty that was driving the volatility seen
10 in March. However, there is still much uncertainty regarding the near-term effect
11 of COVID-19 on the economy and the financial markets, which is why the VIX
12 remains above its long-term average.

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**Figure 2: Daily CBOE VIX
(January 2010 – January 2021)⁶**



Q. Have rating agencies commented on the effects of current market conditions on regulated utilities?

A. Yes, they have. Prior to the COVID-19 pandemic, many utilities had already faced ratings pressure due to the adverse effects of federal tax changes enacted in 2017 (discussed below in Section V.B of my Direct Testimony) and high capital spending related to modernizing infrastructure.⁷ In April 2020, Standard & Poor’s (“S&P”) downwardly revised its outlook on the entire North American utilities sector. In so doing, S&P stated that it expected COVID-19 to create incremental negative

⁶ Source: Bloomberg Professional.

⁷ Standard & Poor’s Ratings Direct: North American Regulated Utilities Face Tough Financial Policy tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic, May 11, 2020, p. 3.

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1 pressure, possibly leading to an increasing number of credit rating downgrades and
2 downward outlook revisions.⁸

3 **Q. What steps have the Federal Reserve and Congress taken to stabilize financial**
4 **markets and support the economy?**

5 A. The Federal Reserve has: (1) decreased the Federal Funds rate twice in March 2020,
6 resulting in a target range of 0.00 percent to 0.25 percent; (2) increased its holdings
7 of both Treasury and mortgaged-back securities; (3) started expansive programs to
8 support credit to large employers: the Primary Market Corporate Credit Facility
9 (“PMCCF”) to provide liquidity for new issuances of corporate bonds; and the
10 Secondary Market Corporate Credit Facility (“SMCCF”) to provide liquidity for
11 outstanding corporate debt issuances; and (4) supported the flow of credit to
12 consumers and businesses through the Term Asset-Backed Securities Loan Facility
13 (“TALF”). In addition, the U.S. Congress also passed the Coronavirus Aid, Relief,
14 and Economic Security (“CARES”) Act in March 2020 and the Consolidated
15 Appropriations Act, 2021 in December 2020 which included \$2.2. trillion and \$900
16 billion, respectively, in fiscal stimulus aimed at also mitigating the economic effects
17 of COVID-19. These expansive monetary and fiscal programs have provided for
18 greater price stability by mitigating the economic effects of the COVID-19
19 pandemic. Nevertheless, as shown in Figure 2 above, there is still uncertainty
20 regarding the near-term effect of COVID-19 on the economy and the financial
21 markets, which is why the VIX is still above its long-term historical level.

⁸ Standard & Poor’s Ratings Direct, COVID-19: The Outlook for North American Regulated Utilities Turns Negative, April 2, 2020.

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1 **Q. What effect will the Federal Reserve’s accommodative monetary policy have**
2 **on interest rates?**

3 A. In December 2020, the Federal Reserve continue to commit to using its full set of
4 “tools” which include keeping the federal funds rate closer to zero and continuing
5 is purchases of both treasuries and mortgage-backed securities.⁹ The goal of this
6 accommodative monetary policy is to achieve the Federal Reserve’s dual mandate
7 of maximum employment and stable prices. Although the current accommodative
8 monetary policy will keep short-term interest rates low, the Federal Reserve has not
9 committed to keeping long-term interest rates low. Long-term interest rates can
10 increase even though monetary policy is accommodative.

11 **Q. In general, what conclusions can be drawn from the relationship between**
12 **short-term and long-term interest rates?**

13 A. The yield curve—which illustrates the difference between long-term and short-term
14 interest rates—is a leading economic indicator of phases of the business cycle. A
15 flat (or inverted) yield curve means that long-term interest rates are similar to (or
16 lower than) short-term interest rates. Such a yield curve shape usually precedes a
17 recession. An upward-sloping yield curve means that long-term interest rates are
18 higher than short-term interest rates. A steepening yield curve indicates that the
19 economy is entering a period of economic expansion following a recession.¹⁰

⁹ Federal Reserve Press Release. December 16, 2020.

¹⁰ “What is a yield curve”, Fidelity.com. <https://www.fidelity.com/learning-center/investment-products/fixed-income-bonds/bond-yield-curve>

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1 The change in yield curve shape over time can be illustrated as a single data series:
2 the interest rate term spread. The term spread is the difference between long-term
3 rates and short-term interest rates.

4 **Q. Have you reviewed the current yield curve and term spread trend to determine**
5 **investors' expectations regarding the economy over the near term?**

6 A. Yes, I have. I calculated the difference between the yield on 10-year Treasury
7 bonds (to represent long-term interest rates) and the yield on 2-year Treasury bonds
8 (to represent short-term interest rates) from January 2017 through January 2021.
9 As shown in Figure 3 below, the term spread has been increasing and has increased
10 to approximately 100 basis points, a level not seen since the first half of 2017. This
11 indicates that investors expect economic growth and inflation to increase in the near
12 term. Given that expectation, investors are motivated to rotate out of long-term
13 government bonds, to avoid being locked into to low interest rates for the long term.
14 An increasing term spread (i.e., a steepening yield curve) signals that higher yields
15 are required by investors to invest in long-term government bonds.

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Figure 3Error! No sequence specified.: Daily Spread Between Yield on 10-year Treasury Bonds and Yield on 2-year Treasury Bonds ¹¹ (January 2017 – January 2021)



Q. Have equity analysts commented on the steepening yield curve?

A. Yes, they have. Several equity analysts have noted that the yield curve is currently steepening and is expected to continue to steepen throughout 2021—which is an indicator that the economy is entering the early expansion phase of the business cycle. For example, in a recent Bloomberg article, Morgan Stanley indicated that it expected a “V-shaped” economic recovery and therefore advised investors to underweight government bonds and overweight equities.¹² Similarly, in a recent Bloomberg article, Goldman Sachs noted the following:

¹¹ Federal Reserve Bank of St. Louis, 10-Year Treasury Constant Maturity Minus 2-Year Treasury Constant Maturity [T10Y2Y], retrieved from FRED, Federal Reserve Bank of St. Louis; <https://fred.stlouisfed.org/series/T10Y2Y>, January 31, 2021.

¹² Ossinger, Joanna. “Morgan Stanley Says Go Risk-On and ‘Trust the Recovery’ in 2021.” Bloomberg.com, 15 Nov. 2020, www.bloomberg.com/news/articles/2020-11-16/morgan-stanley-says-go-risk-on-and-trust-the-recovery-in-2021.

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1 As the economic recovery consolidates next year, we expect
2 to see more differentiation across the curve, with policymakers
3 committing to keeping **front-end rates low**, but higher
4 expectations for real growth and inflation driving **long-end**
5 **rates higher**,” Goldman strategists including Zach Pandl
6 wrote in the report, released Tuesday.

7 This should be especially true in the U.S. due to the Federal
8 Reserve’s new average inflation targeting framework, which
9 commits the central bank to holding off on rate hikes until
10 inflation has reached its target and is on track to overshoot it.¹³

11 Finally, Barron’s noted that Citigroup projected that the yield on the 10-year
12 Treasury Bond is expected to increase in 2021, which prompted Citigroup’s
13 recommendation to favor cyclical stocks (e.g., basic materials, financial services)
14 over defensive stocks (e.g., utilities).¹⁴

15 **Q. Have equity analysts specifically commented on the performance of the utility**
16 **sector over the near-term?**

17 A. Yes. In a recent article, Barron’s surveyed ten market strategists and chief
18 investment officers regarding the outlook for 2021. In addition to forecasting
19 increases in the 10-year Treasury Bond yield and a continued steepening of the
20 yield curve, the market strategists rated utilities as a near-consensus underweight.¹⁵
21 Therefore, the market strategists surveyed by Barron’s are projecting that utilities
22 will underperform the broader market in 2021.

¹³ McCormick, Liz. “Goldman Goes All-In for Steeper U.S. Yield Curves as 2021 Theme.” Bloomberg.com, 10 Nov. 2020, www.bloomberg.com/news/articles/2020-11-10/goldman-goes-all-in-for-steeper-u-s-yield-curves-as-2021-theme. (Emphasis added).

¹⁴ Keown, Callum. “10-Year Treasury Yields Will Rise Into 2021, Citi Says. This 'Aggressive' Equity Strategy Can Outperform.” Barrons.com, 16 Nov. 2020, www.barrons.com/articles/10-year-treasury-yields-will-rise-into-2021-citi-says-this-aggressive-equity-strategy-can-outperform-51605543920.

¹⁵ Jasinski, Nicholas. “The Stock Market Could Gain Another 10% Next Year, Experts Say.” Barron's, 19 Dec. 2020, www.barrons.com/articles/the-stock-market-could-gain-in-2021-51608339301.

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1 **Q. Historically, how has the utility sector performed when the economy was in**
2 **the early stage of a business cycle?**

3 A. In a recent report, Fidelity noted that the utility sector has *historically* been one of
4 the worst performing sectors during the early phase of the business cycle, with a
5 geometric average return of -10.5 percent (And conversely, Fidelity noted that
6 utilities historically outperform the market in recessions and later phases of a
7 business cycle.).¹⁶ The reason for this is that utilities are relatively less affected
8 less by business cycle phases than are other sectors, since consumers need energy
9 in all economic conditions. Therefore, utilities are considered a defensive sector,
10 and they perform relatively well during periods of uncertainty. This relationship
11 mostly held during the past few years as the share prices of utilities were bid up to
12 unsustainable levels as investors responded to economic uncertainty due to the trade
13 war between the U.S. and China and ultimately the COVID-19 pandemic.

14 However, the expected near-term performance of utilities is important for the
15 current proceeding, because, if the utility sector underperforms over the near term
16 (i.e., if stock prices decrease), then the current DCF model (which is specified using
17 historical stock prices), is likely understating the cost of equity that MGUC will
18 experience during the rate period.

19

20

¹⁶ Fidelity Investments, “The Business Cycle Approach to Equity Sector Investing,” 2020.

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1 **Q. What is the effect of high valuations of utility stocks on the DCF model?**

2 A. High valuations have the effect of depressing dividend yields, which results in
3 overall lower estimates of the cost of equity resulting from the DCF model. The
4 relatively low dividend yields demonstrated over the longer historical period imply
5 that the ROE calculated using historical market data in the DCF model may
6 understate the forward-looking cost of equity.

7
8 While recently utilities have underperformed the broader market as a result of the
9 economic effects of COVID-19, it is important to recognize the expected
10 performance of utilities over the near-term. For example, the recent
11 underperformance of utilities was due in part to the excessive valuations that
12 existed prior to the start of the pandemic. These valuations as noted above are still
13 well above historical averages. As a result, Charles Schwab has classified the
14 Utilities sector as “Underperform,” noting that:

15 The Utilities sector has tended to perform relatively better
16 when concerns about slowing economic growth resurface, and
17 to underperform when those worries fade. That’s partly
18 because of the sector’s traditional defensive nature and steady
19 revenues—people need water, gas and electric services during
20 all phases of the business cycle. And low interest rates that
21 typically come with a weak economy provide cheap funding
22 for the large capital expeditions required in this industry.

23 However, valuations have been driven up in recent years as
24 investors have reached for yield in this new era of low interest
25 rates; this may decrease the sector’s traditional defensive
26 characteristics. And while interest rates are expected to
27 remain generally low, they could edge higher as the economy
28 continues to expand. On the flip side, there is the potential for
29 a renewed decline in the economy to push rates even lower, or
30 there could be significant government funding to Utilities as

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1 part of clean-energy initiatives that would benefit the sector's
2 profit outlook.¹⁷

3 As Charles Schwab noted the utility sector underperforms in periods of economic
4 growth; however, Charles Schwab also believes that given the high valuations of
5 the utility sector even if volatility were to increase again that the utility sector might
6 still underperform in a market setting where utilities had traditional been
7 overperformers.

8 Therefore, the current, high valuations in the utilities sector which is expected to
9 result in underperformance over the near-term means that the DCF model results
10 must be interpreted with extreme caution so as to not understate the cost of equity
11 during the period that MGUC's rates will be in effect.

12 **Q. What are your conclusions regarding market conditions and their effect on the**
13 **cost of equity for MGUC?**

14 A. Given the uncertainty and volatility that has characterized capital markets in 2020,
15 it is reasonable that equity investors would now require a higher return on equity to
16 compensate them for the additional risk associated with owning common stock
17 under these market conditions. As shown in Figure 2 above, volatility as measured
18 by the VIX is still above long-term averages. As a result, there is still uncertainty
19 in the market which means greater risk and thus higher return requirements for
20 investors. Further, while the Federal Reserve will keep short-term interest rates
21 low over the next few years to support the economic recovery this does not indicate
22 that long-term interest rates cannot increase. In fact, many equity analysts believe

¹⁷ Charles Schwab, Utilities Sector Rating: Underperform, February 11, 2021.

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1 long-term interest rates will increase in 2021 as the economy enters the early
2 expansion phase of the business cycle. Historically, the utility sector has
3 underperformed the broader market as interest rates increase and the economy
4 recovers.

5 Investors' current expectations regarding the economy highlights the importance of
6 using forward-looking inputs in the models used to estimate the cost of equity.
7 While the share prices of utilities have declined in response to the economic effects
8 of the COVID-19 pandemic, current utility valuations are still well above the long-
9 term average. The current high valuations result in low dividend yields for utilities,
10 which means that DCF models using recent historical data likely underestimate
11 investors' required return for MGUC over the period that rates will be in effect.
12 This consideration regarding the DCF model is important especially in light of the
13 expectation that the utility sector will underperform relative to the broader market
14 as the economy recovers from the COVID-19 pandemic. Conversely, two out of
15 three inputs (i.e., risk-free rate and market risk premium) in the CAPM can be
16 estimated using forward-looking projections. Therefore, the CAPM is likely to
17 capture more effectively the economic conditions expected by investors over the
18 near-term. This highlights the importance of considering the results of each of the
19 models to reflect investors' expectations of market conditions over the period that
20 the rates established in this proceeding will be in effect.

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1 Federal Tax Policy Changes

2 Q. How has federal tax legislation affected regulated utilities?

3 A. The Tax Cuts and Jobs Act of 2017 (“TCJA”) lowered federal income taxes, ended
4 bonus depreciation, and required utilities to return excess Accumulated Deferred
5 Income Taxes (“ADIT”). This had the effect of reducing utility revenues, which
6 reduced Funds From Operations (“FFO”) metrics across the sector and led to
7 weaker credit metrics and negative ratings actions for some utilities.¹⁸ After the
8 TCJA legislation was enacted, credit rating agencies commented on the adverse
9 credit impact on regulated utilities.¹⁹

**10 Q. How have rating agencies responded to the TCJA’s effect on utility financial
11 risk?**

12 A. In June 2018, Moody’s downwardly revised its outlook for the entire regulated
13 utility industry from Stable to Negative for the first time ever, citing ongoing
14 concerns about the negative effect of the TCJA on cash flows of regulated utilities.
15 Since then, Moody’s has downgraded the credit ratings of several utilities based in
16 part on the effects of the TJCA on financial metrics, including the Company’s
17 holding company WEC and its affiliate Wisconsin Gas LLC. As shown in Figure
18 4, the downgrades continued into 2020.

¹⁸ FitchRatings, Special Report, What Investors Want to Know, “Tax Reform Impact on the U.S. Utilities, Power & Gas Sector”, January 24, 2018.

¹⁹ FitchRatings, Special Report, What Investors Want to Know, “Tax Reform Impact on the U.S. Utilities, Power & Gas Sector”, January 24, 2018; Standard & Poor’s Ratings, “Industry Top Trends 2019, North America Regulated Utilities”, November 8, 2018.

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1

Figure 4: Credit Rating Downgrades Resulting from the TCJA

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
Electric Transmission Texas	Moody's	Baa1	Baa2	3/24/2020
New Jersey Natural Gas Company	Moody's	Aa3	A1	3/18/2020
Consolidated Edison Company of New York	Moody's	A3	Baa1	3/17/2020
Consolidated Edison, Inc.	Moody's	Baa1	Baa2	3/17/2020
Washington Gas Light Company	Moody's	A2	A3	1/30/2020
Public Service Co. of North Carolina, Inc.	Moody's	A3	Baa1	1/30/2020
Wisconsin Power and Light Company	Moody's	A2	A3	12/11/2019
Wisconsin Gas LLC	Moody's	A2	A3	11/20/2019
Vectren Utility Holdings	Moody's	A2	A3	10/25/2019
Southern Indiana Gas & Electric Company	Moody's	A2	A3	10/25/2019
Indiana Gas Company	Moody's	A2	A3	10/25/2019
El Paso Electric Company	Moody's	Baa1	Baa2	9/17/2019
Questar Gas Company	Moody's	A2	A3	8/15/2019
DTE Gas Company	Moody's	A2	A3	7/22/2019
South Jersey Gas Company	Moody's	A2	A3	7/17/2019
Central Hudson Gas & Electric	Moody's	A2	A3	7/12/2019
Oklahoma Gas & Electric Company	Moody's	A2	A3	5/31/2019
American Water Works	Moody's	A3	Baa1	4/1/2019
Niagara Mohawk Power Corporation	Moody's	A2	A3	3/29/2019
KeySpan Gas East Corporation (KEDLI)	Moody's	A2	A3	3/29/2019
Xcel Energy	Moody's	A3	Baa1	3/28/2019
ALLETE, Inc.	Moody's	A3	Baa1	3/26/2019
Brooklyn Union Gas Company (KEDNY)	Moody's	A2	A3	2/22/2019
Avista Corp.	Moody's	Baa1	Baa2	12/30/2018
Consolidated Edison Company of New York	Moody's	A2	A3	10/30/2018
Consolidated Edison, Inc.	Moody's	A3	Baa1	10/30/2018
Orange and Rockland Utilities	Moody's	A3	Baa1	10/30/2018
Southwestern Public Service Company	Moody's	Baa1	Baa2	10/19/2018
Dominion Energy Gas Holdings	Moody's	A2	A3	9/20/2018
Piedmont Natural Gas Company, Inc.	Moody's	A2	A3	8/1/2018
WEC Energy Group, Inc.	Moody's	A3	Baa1	7/12/2018
Wisconsin Energy Capital	Moody's	A3	Baa1	7/12/2018
Integrus Holdings Inc.	Moody's	A3	Baa1	7/12/2018
OGE Energy Corp.	Moody's	A3	Baa1	7/5/2018

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1 At that time, FitchRatings also recognized the implications of tax reform and
2 indicated that any ratings actions on its part would be guided by the response of
3 regulators to the TCJA as well as by the demonstrated ability of utility company
4 management teams to manage the cash flow implications of the TCJA. Fitch
5 offered regulatory solutions to provide rate stability and to moderate changes to
6 cash flow in the near term, including increasing the authorized ROE and/or equity
7 ratio.²⁰

8 **Q. Has the Company experienced a downgrade related to cash flow metrics**
9 **resulting from tax reform?**

10 A. No, however, as shown in Figure 4, WEC and Integrys, the parent companies of
11 MGUC, as well as its affiliate Wisconsin Gas LLC, were recently downgraded by
12 Moody's due, in part, to the effect of the TCJA on the cash flows of WEC. Moody's
13 indicated that "[t]he downgrade of WEC, WECC, and the Integrys entities reflects
14 our expectation that the negative cash flow impact of tax reform, along with
15 incremental debt to fund capital expenditures, will cause a deterioration in
16 consolidated metrics."²¹

²⁰ FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

²¹ Moody's Investors Service, Rating Action: Moody's downgrades WEC Energy, Wisconsin Energy Capital and Integrys to Baa1 from A3; stable outlook, July 12, 2018.

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1 **Q. Have other utility commissions recognized that the TCJA had an adverse**
2 **impact on utility cash flows?**

3 A. Yes, they have. For example, the Oregon Public Utilities Commission (in 2019),²²
4 the Wyoming Public Service Commission (in 2019),²³ and the Utah Public Service
5 Commission (in 2020)²⁴ have acknowledged the negative effect of the TCJA on the
6 cash flow of utilities.

7 **Conclusions**

8 **Q. What conclusions do you draw from your analysis of capital market**
9 **conditions?**

10 A. Upon analyzing current capital market conditions, my conclusions are threefold:

11 (1) ROE estimation model variables are currently being affected by atypical
12 market conditions: equity market volatility is high (which equates to
13 significant risk to equity, which increases the return on equity that investors
14 expect in exchange for taking on such incremental risk), and utility stock
15 valuations are high (which keeps dividend yields relatively low). Therefore,
16 in this proceeding, the Commission should consider the results of multiple
17 types of ROE estimation models to determine the appropriate ROE for
18 MGUC.

²² See In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue 3,500,000 Shares of Common Stock, Docket UF 4308, Order No. 19-067 (Feb. 23, 2019); In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue and Sell \$600,000,000 of Debt Securities, UF 4313, Order No. 19-249 (July 30, 2019); In the Matter of Portland General Electric Company, Request for Authority to Extend the Maturity of an Existing \$500 Million Revolving Credit Agreement, Docket UF 4272(3), Order No. 19-025 (Jan. 23, 2019).

²³ In the Matter of Questar Gas Company dba Dominion Energy Wyoming's Application for Approval of Amended Stipulation Previously Approved in Docket No. 30010-150-GA-16, Docket No. 30010-180-GA-18 (Record No. 15138) (Aug. 20, 2019).

²⁴ Report and Order, Docket No. 19-057-02, Dominion Energy Utah, February 25, 2020, at 6.

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(2) These historically atypical capital market conditions are not expected to persist over the long term or over the period when rates from this proceeding will be in effect. Therefore, it is important that the Commission consider the results of ROE estimation models using projected market data (in addition to current market data) to estimate the cost of equity that MGUC is likely to experience during the rate period.

(3) In response to capital market conditions, credit rating agencies have voiced significant concern about the cash flow metrics of utilities. This increases investor perception of the risk of investing in utilities. Therefore, it is important that the Commission authorize an ROE for MGUC that is adequate to support the Company's cash flow and thereby enable it to attract capital at reasonable terms.

Q. Has the Commission considered capital market conditions in determining authorized ROEs?

A. Yes, it has. In a recent rate case for Consumers Energy Company (Case No. U-20697), the Commission noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past.²⁵ Specifically, the Commission noted that:

[i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs,

²⁵ Michigan Public Service Commission Order, Cause No. U-20697, Consumers Energy Company, December 17, 2020, at 165.

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1 as argued by many intervenors, is also a relevant
2 consideration. **It is also important to consider how extreme**
3 **market reactions to global events, as have occurred in the**
4 **recent past, may impact how easily capital will be able to**
5 **be accessed during the future test period should an**
6 **unforeseen market shock occur. The Commission will**
7 **continue to monitor a variety of market factors in future**
8 **rate cases to gauge whether volatility and uncertainty**
9 **continue to be prevalent issues that merit more**
10 **consideration in setting the ROE.**²⁶

11 **VI. PROXY GROUP SELECTION**

12 **Q. Please provide a brief profile of MGUC.**

13 A. MGUC is a natural gas distribution company that is a wholly owned subsidiary of
14 Integrys Holding, Inc. (“Integrys”), which is a wholly owned subsidiary of WEC
15 Energy Group. MGUC distributes natural gas to approximately 180,000 customers
16 in southern and western Michigan.²⁷ As of December 31, 2019, MGUC’s net utility
17 natural gas plant in Michigan was approximately \$290 million.²⁸ In 2019, MGUC
18 had total natural gas sales volume in Michigan of approximately 35 million Mcf,
19 composed of approximately 37 percent residential, 15 percent commercial, 3
20 percent industrial, 35 percent transportation, and 10 percent customer choice.²⁹

21 Integrys has a long-term rating of A- (Outlook: Stable) from S&P and Baa1
22 (Outlook: Stable) from Moody’s.³⁰

²⁶ Michigan Public Service Commission Order, Cause No. U-20697, Consumers Energy Company, December 17, 2020, at 165-166. (Emphasis added)

²⁷ MGUC website.

²⁸ Michigan Gas Utilities Corporation, 2019 Annual LDC filing to the Michigan Public Service Commission, pgs. 301, 306C, 313.

²⁹ *Id.*, at 302 and 305B.

³⁰ S&P Global Market Intelligence

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1 **Q. Why have you used a group of proxy companies to estimate the cost of equity**
2 **for MGUC?**

3 A. In this proceeding, we focus on estimating the cost of equity for a natural gas utility
4 company that is not itself publicly traded. Because the cost of equity is a market-
5 based concept and because MGUC's operations do not make up the entirety of a
6 publicly traded entity, it is necessary to establish a group of companies that is both
7 publicly traded and comparable to the Company in certain fundamental business
8 and financial respects to serve as its "proxy" in the ROE estimation process.
9 Even if MGUC was a publicly traded entity, it is possible that transitory events
10 could bias its market value over a given period. A significant benefit of using a
11 proxy group is that it moderates the effects of unusual events that may be associated
12 with any one company. The proxy companies used in my analyses all possess a set
13 of operating and risk characteristics that are substantially comparable to the
14 Company, and thus provide a reasonable basis to derive and estimate the
15 appropriate ROE for MGUC.

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

17 A. I began with the group of ten companies that Value Line classifies as Natural Gas
18 Distribution Utilities and applied the following screening criteria to select
19 companies that:

- 20 • pay consistent quarterly cash dividends, because companies that do not
21 cannot be analyzed using the Constant Growth DCF model;
- 22 • have investment grade long-term issuer ratings from S&P and/or Moody's;

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- 1 • have positive long-term earnings growth forecasts from at least two utility
- 2 industry equity analysts;
- 3 • derive more than 70.00 percent of their total operating income from
- 4 regulated operations;
- 5 • derive more than 60.00 percent of regulated operating income from gas
- 6 distribution operations;
- 7 • have a mean Constant Growth DCF result greater than 7 percent; and
- 8 • were not parties to a merger or transformative transaction during the
- 9 analytical periods relied on.

10 **Q. Please explain why you excluded companies from your proxy group with a**
11 **mean Constant Growth DCF result less than 7 percent?**

12 It is appropriate to exclude companies from the proxy group with a mean Constant
13 Growth DCF result below a specified threshold at which equity investors would
14 consider such returns to provide an insufficient return increment above long-term
15 debt costs. For example, the average credit rating for the companies in my proxy
16 group is A-. The average yield on Moody's A-rated utility bonds for the 30 trading
17 days ending January 31, 2021, was 2.86 percent. Thus, I have eliminated
18 companies from my proxy group with mean Constant Growth DCF results lower
19 than 7.00% because such returns would provide equity investors a risk premium
20 only 414 basis points above A-rated utility bonds.

1 Q. Did your 7 percent risk premium screen result in the exclusion of any
2 additional companies from your proxy group.

3 A. No, it did not. While I applied the screening criterion to my proxy group, each of
4 the natural gas distribution companies shown in Figure 6 had a mean Constant
5 Growth DCF result greater than 7 percent.

6 Q. What is the composition of your proxy group?

A. The screening criteria discussed above resulted in a proxy group consisting of the seven companies listed in Figure 5 below

9

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

11 **VII. COST OF EQUITY ESTIMATION**

12 **Q. Please briefly discuss the ROE in the context of the regulated rate of return**
13 **(“ROR”).**

14 A. The ROE is the cost rate applied to the equity capital in the ROR. The ROR for a
15 regulated utility is the weighted average cost of capital, in which the cost rates of
16 the individual sources of capital are weighted by their respective book values.

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1 While the costs of debt and preferred stock can be directly observed, the cost of
2 equity is market-based and, therefore, must be estimated based on observable
3 market data.

4 **Q. How is the required ROE determined?**

5 A. The required ROE is estimated by using one or more analytical techniques that rely
6 on market-based data to quantify investor expectations regarding equity returns,
7 adjusted for certain incremental costs and risks. Informed judgment is then applied
8 to determine where the company's cost of equity falls within the range of results.
9 The key consideration in determining the cost of equity is to ensure that the
10 methodologies employed reasonably reflect investors' views of the financial
11 markets in general, as well as the subject company (in the context of the proxy
12 group), in particular.

13 **Q. What methods did you use to determine the market-required ROE of MGUC**
14 **for the rate period?**

15 A. To estimate the ROE required by the market for MGUC over the rate period, I
16 considered the results of:

- 17 • a Constant Growth DCF model,
- 18 • a Multi-Stage DCF model,
- 19 • the CAPM,
- 20 • the ECAPM, and
- 21 • a Risk Premium analysis.

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1 As discussed in more detail below, a reasonable estimate of the market-required
2 ROE appropriately considers multiple methodologies and the reasonableness of
3 their individual and collective results.

4 **A. Importance of Multiple Analytical Approaches**

5 **Q. Why is it important to use more than one analytical approach?**

6 A. Because a company's current COE is not directly observable, it must be
7 estimated—which practitioners do, using both quantitative and qualitative
8 information. Analysts and investors are inclined to gather and evaluate as much
9 relevant data as reasonably can be analyzed. Several types of models have been
10 developed to estimate the COE. And I use multiple of those approaches. As a
11 practical matter, however, all the models available for estimating the cost of equity
12 are subject to limiting assumptions or other methodological
13 constraints. Consequently, many well-regarded finance texts recommend using
14 multiple approaches when estimating the cost of equity. For example, Copeland,
15 Koller, and Murrin³¹ suggest using the CAPM and Arbitrage Pricing Theory model,
16 while Brigham and Gapenski³² recommend the CAPM, DCF, and Bond Yield Plus
17 Risk Premium approaches.

³¹ Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

³² Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

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1 **Q. Do current market conditions increase the importance of using multiple**
2 **analytical approaches?**

3 A. Yes, they do. Equity market volatility is currently high, which increases the return
4 on equity that investors expect in exchange for taking on such incremental risk.
5 However, relatively high utility stock valuations translate into relatively lower
6 dividend yields, which produce lower cost of equity estimates in a DCF analysis.
7 Also, low interest rates affect two variables in the CAPM: the risk-free rate and the
8 market risk premium (which is calculated as the expected market return less the
9 risk-free rate). Therefore, it is important to use multiple analytical approaches in
10 order to arrive at an accurate estimate of COE.

11 These historically atypical capital market conditions are not expected to persist over
12 the long term or over the period when rates from this proceeding will be in effect.
13 Therefore, where possible, it is also important to consider using projected market
14 data in the models—in order to estimate the COE that the Company is likely to
15 experience during the rate period.

16 **Q. Has the Commission recognized that it is important to consider the results of**
17 **multiple models?**

18 A. Yes. It is my understanding that in its recent order for DTE Gas Company (“DTE
19 Gas”), the Commission considered the results of each of the models presented by
20 the ROE witnesses which included the DCF, CAPM, ECAPM and Risk Premium.³³
21 The Commission also considered authorized ROEs in other states, increased

³³ Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

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1 volatility in capital markets and the company-specific business risks of DTE Gas.
2 Ultimately, the Commission authorized a 10.00 percent ROE which the
3 Commission indicated “falls within DTE Gas’ recommended range and is only
4 slightly above the Staff’s proposed range”.³⁴ The Commission also noted that a
5 10.00 percent ROE for DTE Gas achieves the following:

6 With these considerations in mind, the Commission finds that
7 an ROE of 10.00% appropriately balances the interests of the
8 company with those of its ratepayers. It is high enough to
9 ensure investor confidence in the financial soundness of DTE
10 Gas’ business, but low enough to protect the company’s
11 customers from unnecessarily burdensome rates. Further, it
12 accomplishes the objectives of adequately compensating DTE
13 Gas for its company-specific business risk, ensuring the
14 financial well-being of the utility, and maintaining a strong
15 ability to attract capital.³⁵

16 **Q. What are your conclusions about the results of the DCF and CAPM models?**

17 A. Recent market data that is used as the basis for the assumptions for both models
18 have been affected by market conditions. As a result, relying exclusively on
19 historical assumptions in these models—without considering whether these
20 assumptions are consistent with investors’ future expectations—will underestimate
21 the ROE that investors would require over the period that the rates in this case are
22 to be in effect. In this instance, relying on the historically low dividend yields that
23 are not expected to continue over the period that the new rates will be in effect will
24 underestimate the ROE for MGUC.

³⁴ *Id.* at 53.

³⁵ *Id.*

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Furthermore, as discussed in Section V above, Treasury bond yields have experienced unprecedented volatility in recent months due to the economic effects of COVID-19. Therefore, the use of current averages of Treasury bond yields as the estimate of the risk-free rate in the CAPM is not appropriate since recent market conditions are not expected to continue over the long term. Instead, practitioners should rely on projected yields of Treasury bonds in the CAPM. The projected Treasury Bond yields result in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

Constant Growth DCF Model

Q. Please describe the DCF approach to ROE estimation.

A. The DCF approach to ROE estimation is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

P_0 represents the current stock price, D_1 to D_∞ are expected future dividends, and k is the discount rate (aka the market-required ROE). Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

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1 D_0 is the expected dividend yield, and g is the expected long-term growth rate.
2 Equation [2] is often referred to as the Constant Growth DCF model.

3 **Q. What assumptions are required to simplify the DCF model to the Constant**
4 **Growth DCF model?**

5 A. Simplifying the DCF model into the Constant Growth DCF model requires four
6 assumptions: (1) the growth rate for earnings and dividends is constant; (2) the
7 dividend payout ratio is stable; (3) a constant P/E ratio; and (4) the discount rate is
8 greater than the expected growth rate. To the extent any of these assumptions is
9 violated, considered judgment and/or specific adjustments should be applied to the
10 model results.

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

13 A. The dividend yield in my Constant Growth DCF model is based on (1) the proxy
14 companies' current annual dividend and (2) the proxy companies' average closing
15 stock prices over the 30, 90, and 180 trading days ending January 31, 2021.

16 **Q. Why did you use three averaging periods for stock prices?**

17 A. In my Constant Growth DCF model, I use an average of recent trading days to
18 calculate the price term (P_0) in the model to ensure that the ROE is not skewed by
19 anomalous events that may affect stock prices on any given trading day. The
20 averaging period should also be reasonably representative of expected capital
21 market conditions over the long term. However, by necessity, practitioners rely on
22 historical prices which, as discussed above, have been volatile and are currently at

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1 unsustainably high levels. Under these circumstances, where current market
2 conditions cannot be expected to continue throughout the rate period, it is important
3 to recognize that current average prices in the Constant Growth DCF model are not
4 consistent with forward-looking market expectations. Therefore, the results of my
5 Constant Growth DCF model using historical data may underestimate the forward-
6 looking cost of equity. As a result, I place more weight on the median to median-
7 high results produced by my Constant Growth DCF model.

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

10 A. Yes, I did. Since utility companies tend to increase their quarterly dividends at
11 different times throughout the year, it is reasonable to assume that dividend
12 increases will be evenly distributed over calendar quarters. Given that assumption,
13 it is reasonable to apply one-half of the expected annual dividend growth rate (i.e.,
14 the projected earnings growth rate used for the g term in the DCF model) for
15 purposes of calculating the expected dividend yield component of the DCF model.
16 This adjustment ensures that the expected first year dividend yield is, on average,
17 representative of the coming twelve-month period and does not overstate the
18 aggregate dividends to be paid during that time.

19 **Q. Why is it important to select appropriate measures of long-term growth in**
20 **applying the DCF model?**

21 A. In its Constant Growth form, the DCF model (i.e., Equation [2]) assumes a single
22 long-term earnings growth rate in perpetuity for the proxy group. In order to reduce
23 the long-term growth rate to a single measure, one must assume that the dividend

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1 payout ratio remains constant and that earnings per share, dividends per share, and
2 book value per share all grow at the same constant rate. Over the long run, however,
3 dividend growth can only be sustained by earnings growth. For example, earnings
4 growth rates tend to be least influenced by capital allocation decisions that
5 companies may make in response to near-term changes in the business
6 environment. Since such decisions may directly affect near-term dividend payout
7 ratios, estimates of earnings growth are more indicative of long-term investor
8 expectations than are dividend or book value growth estimates.

9 **Q. What sources of long-term growth rates did you rely on in your Constant**
10 **Growth DCF model?**

11 A. My Constant Growth DCF model incorporates the following sources of long-term
12 growth rates: (1) consensus long-term earnings growth estimates from Zacks
13 Investment Research; (2) consensus long-term earnings growth estimates from
14 Thomson First Call (provided by Yahoo! Finance); and (3) long-term EPS growth
15 estimates from Value Line.

16 **Q. Have you made any adjustments to the earnings growth rates data from third**
17 **party sources?**

18 A. Yes, I have. Schedule D8 details the adjustment that I made to the EPS growth rate
19 for Northwest Natural Gas (NWN) as projected by Value Line. Value Line
20 calculates its projection as the compound annual growth rate between (a) the
21 historical actual average EPS over the 2017-2019 period, and (b) its own projected
22 EPS level for the 2023-2025 period. However, NWN had a *negative* 1.94 EPS in

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1 2017 (compared to positive EPS values in 2018 and 2019), which materially
2 changes the starting point for the compound annual growth rate calculation.

3 In my adjustment, I use the mean EPS for 2018 and 2019 (rather than 2017, 2018,
4 and 2019). The resulting compound annual growth rate for NWN equals 5.97
5 percent (instead of 24.48 percent). I have used this adjusted growth rate for NWN
6 in my Constant Growth DCF model.

7 **Multi-Stage DCF Model**

8 **Q. What other forms of the DCF model have you considered?**

9 A. While I am able to adjust the Value Line projected earnings growth rate for NWN
10 to remove the effect of the negative earnings per share in 2017, I am unable to adjust
11 the growth rates published by either Yahoo! Finance or Zacks given that the
12 published growth rates are consensus estimates. As shown in Schedule D8, South
13 Jersey Industries ("SJI") has a projected earnings growth rate from Yahoo! Finance
14 and Zacks of 24.50 percent while Spire, Inc. ("SR") has a 16.50 percent projected
15 earnings growth rate from Zacks. The projected earnings growth rate for SJI and
16 SR could be considered high. However, I do not believe it is not appropriate to
17 remove a high growth rate unless it is determined that the data point is the result of
18 an error. Absent an error, there are other alternatives for addressing disparate data.
19 One approach is to select a measure of central tendency other than the mean, as I
20 have done by reporting the median results for my Constant Growth DCF analysis.
21 In general, the median is not affected to a large degree by the presence of outliers
22 on both the high and low end. Another alternative is to consider the results of a
23 Multi-Stage form of the DCF model, which is an extension of the Constant Growth

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1 form, and enables the analyst to specify different growth rates over multiple stages.
2 As with the Constant Growth DCF model, the Multi-Stage form defines the cost of
3 equity as the discount rate that sets the current price equal to the discounted value
4 of future cash flows.

5 **Q. Please generally describe the structure of your Multi-Stage DCF model.**

6 A. The Multi-Stage DCF model sets a company's current stock price equal to the
7 present value of future cash flows received over three "stages." In all three stages,
8 cash flows are equal to the annual dividend payments that stockholders receive.
9 Stage One is a short-term growth period that consists of the first five years; Stage
10 Two is a transition period from the short-term growth rate to the long-term growth
11 rate (i.e., years six through 10); and Stage Three is a long-term growth period that
12 begins in year 11 and continues in perpetuity (i.e., year 200). The ROE is then
13 calculated as the rate of return that results from the initial stock investment and the
14 dividend payments over the analytical period.

15 **Q. Please summarize the EPS growth rates used in your Multi-Stage DCF model.**

16 A. As shown in Schedule D9, I began with the current annualized dividend as of
17 January 31, 2021 for each proxy group company. In the first stage of the model,
18 the current annualized dividend is escalated based on the average of the three- to
19 five-year earnings growth estimates reported by Zacks, Yahoo! Finance, and Value
20 Line. For the third stage, I relied on long-term projected growth in Gross Domestic
21 Product ("GDP"). The second stage growth rate is a transition from the first stage
22 growth rate to the long-term growth rate on a geometric average basis.

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1 **Q. How did you calculate the long-term GDP growth rate?**

2 A. As shown in Schedule D10, the long-term growth rate of 5.56 percent is based on
3 real GDP growth rate of 3.21 percent from 1929 through 2019,³⁶ and a projected
4 inflation rate of 2.27 percent. The projected inflation rate is based on three
5 measures: (1) the average long-term projected growth rate in the Consumer Price
6 Index (“CPI”) of 2.20 percent;³⁷ (2) the compound annual growth rate of the CPI
7 for all urban consumers for 2031-2050 of 2.32 percent as projected by the Energy
8 Information Administration (“EIA”); and (3) the compound annual growth rate of
9 the GDP chain-type price index for 2031-2050 of 2.30 percent, also reported by the
10 EIA.³⁸

11 **Q. Do the assumptions in the Multi-Stage DCF model address the effect of low**
12 **dividend yields on the DCF results?**

13 A. No, they do not. While the Multi-Stage DCF model provides for changes in growth
14 over time, it does not address the abnormally low dividend yields for utility stocks
15 and the effect of those low dividend yields on the DCF model, specifically the
16 understated ROEs that result from the use of these assumptions. For that reason, I
17 have also considered the results of alternative risk-premium based methodologies,
18 which I will discuss later in my Direct Testimony.

³⁶ U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, December 22, 2020.

³⁷ Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14.

³⁸ Energy Information Administration, Annual Energy Outlook 2020 at Table 20, January 29, 2020.

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1 **Discounted Cash Flow Model Results**

2 **Q. What were the results of your DCF analyses?**

3 A. Figure 6 (see also Schedule D8 and Schedule D9) presents the range of the Constant
4 Growth and Multi-Stage DCF results produced by my proxy group. As shown in
5 Figure 6, for the Constant Growth DCF, the median DCF results range from 9.61
6 percent to 9.92 percent, and the median high results are in the range of 12.58 percent
7 to 12.98 percent, while for the Multi-Stage DCF, the median DCF results range
8 from 9.44 percent to 9.88 percent, and the median high results are in the range of
9 10.24 percent to 10.76 percent.

10

Figure 6: Discounted Cash Flow Results

	Median-Low	Median	Median-High
Constant Growth DCF			
30-Day Average	7.98%	9.92%	12.98%
90-Day Average	7.98%	9.68%	12.71%
180-Day Average	7.94%	9.61%	12.58%
Multi-Stage DCF			
30-Day Average	9.36%	9.88%	10.76%
90-Day Average	9.09%	9.71%	10.41%
180-Day Average	8.97%	9.44%	10.24%

11

12 **Q. How did you calculate the range of results produced by the Constant Growth**
13 **DCF model?**

14 A. I calculated the “median-low” DCF result using the minimum growth rate (i.e., the
15 lowest of the Thomson First Call, Zacks, and Value Line earnings growth rates) for
16 each of the proxy group companies. Thus, the low result reflects the minimum

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1 DCF result for the proxy group. I used a similar approach to calculate the “median-
2 high” results (i.e., using the highest growth rate for each proxy group company).
3 The “median” results were calculated using the average growth rates from all three
4 sources.

5 **Q. What are your conclusions about the results of the DCF model?**

6 A. To the extent that utility valuations are high and may not be sustainable, it is
7 important to consider the results of the DCF model with caution. This means that
8 the results of the current DCF models are below where they would otherwise be
9 under more normal market conditions. Therefore, while I have given weight to the
10 results of the Constant Growth and Multi-Stage DCF models, my final
11 recommendation also gives weight to the results of the CAPM, ECAPM, and Bond
12 Yield Plus Risk Premium model.

13 **CAPM Analysis**

14 **Q. Please briefly describe the Capital Asset Pricing Model.**

15 A. The CAPM is a risk premium approach that estimates the cost of equity for a given
16 security as a function of a risk-free return plus a risk premium to compensate
17 investors for the non-diversifiable, systematic risk of that security. Systematic risk
18 is the risk inherent in the entire market or market segment—which cannot be
19 diversified away using a portfolio of assets. Unsystematic risk is the risk of a
20 specific company that can, theoretically, be mitigated through portfolio
21 diversification.

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1 The CAPM is defined by four components, each of which must be a forward-
2 looking estimate:

$$3 \quad K_e = r_f + \beta(r_m - r_f) \quad [3]$$

4 Where:

5 K_e = the market-required ROE of an individual security;

6 β = Beta coefficient of an individual security;

7 r_f = the risk-free rate of return; and

8 r_m = the market-required return on the equity market as a whole.

9 The term $(r_m - r_f)$ represents the Market Risk Premium (MRP). According to the
10 theory underlying the CAPM, since unsystematic risk can be diversified away,
11 investors should only be concerned with systematic risk. Systematic risk is
12 measured by Beta. Beta is a measure of the volatility of a security as compared to
13 the market as a whole. It is defined as:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

14 The variance of the market return (i.e., $\text{Variance}(r_m)$) measures the uncertainty of
15 the general market. The covariance between the return on a specific security and
16 the general market (i.e., $\text{Covariance}(r_e, r_m)$) measures the extent to which the
17 return on that security will respond to a given change in the general market return.
18 Thus, Beta represents the risk of the security relative to the general market.

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1 **Q. What risk-free rate did you use in your CAPM analysis?**

2 A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day
3 average yield on 30-year U.S. Treasury bonds (i.e., 1.77 percent);³⁹ (2) the
4 projected 30-year U.S. Treasury bond yield for Q2 2021 through Q2 2022 (i.e., 2.06
5 percent);⁴⁰ and (3) the projected 30-year U.S. Treasury bond yield for 2022 through
6 2026 (i.e., 2.80 percent).⁴¹

7 **Q. Would you place more weight on one of these scenarios?**

8 A. Yes. Based on current market conditions, I place more weight on the results of the
9 projected yields on the 30-year Treasury bonds. As discussed previously, the
10 estimation of the cost of equity in this case should be forward-looking because it is
11 the return that investors would receive over the future rate period. Therefore, the
12 inputs and assumptions used in the CAPM analysis should reflect the expectations
13 of the market at that time. While I have included the results of a CAPM analysis
14 that relies on the current average risk-free rate, this analysis fails to take into
15 consideration the effect of the market's expectations for interest rate increases on
16 the cost of equity.

17 **Q. What Beta coefficients did you use in your CAPM analysis?**

18 A. As shown in Schedule D11, I used the Beta coefficients for the proxy group
19 companies as reported by Bloomberg and Value Line. The Beta coefficients
20 reported by Bloomberg are based on ten years of weekly returns relative to the S&P

³⁹ Bloomberg Professional, as of January 31, 2021.

⁴⁰ Blue Chip Financial Forecasts, Vol. 40, No. 2, February 1, 2021, at 2.

⁴¹ Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14.

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1 500 Index. Value Line's Betas are based on five years of weekly returns relative
2 to the New York Stock Exchange Composite Index. Both measures are an
3 "adjusted Beta".

4 Additionally, as shown in Schedule D12, I also considered an additional CAPM
5 analysis which relies on the long-term average utility Beta coefficient for the
6 companies in my proxy group. The long-term average utility Beta coefficient was
7 calculated as an average of the Value Line Beta coefficients for the companies in
8 my proxy group from 2011 through 2020.

9 **Q. How did you estimate the Market Risk Premium in the CAPM?**

10 A. I estimated the Market Risk Premium ("MRP") as the difference between the
11 implied expected equity market return and the risk-free rate. The expected return
12 on the S&P 500 Index is calculated using the Constant Growth DCF model
13 discussed earlier in my testimony for the companies in the S&P 500 Index for which
14 dividend yields and Value Line long-term earnings projections are available.
15 Based on an estimated market capitalization-weighted dividend yield of 1.58
16 percent and a weighted long-term growth rate of 12.45 percent, the estimated
17 required market return for the S&P 500 Index is 14.13 percent. The implied market
18 risk premium over the current 30-day average of the 30-year U.S. Treasury bond
19 yield, and projected yields on the 30-year U.S. Treasury bond, ranges from 11.33
20 percent to 12.36 percent.

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1 **Q. Have other regulators endorsed the use of a forward-looking market risk**
2 **premium?**

3 A. Yes, they have. For example, the Minnesota Department of Commerce
4 (“Minnesota DOC”) relied on a forward-looking market return (estimated using a
5 Constant Growth DCF model) in the CAPM for Great Plains Natural Gas Company
6 (Docket No. G-004/GR-19-511). Specifically, it used the dividend yield reported
7 by S&P for the S&P 500 and the three- to five-year earnings growth estimate for
8 the State Street Global Advisors S&P 500 exchange traded fund (“ETF”), which
9 resulted in a projected market return of 13.44 percent.⁴² The Minnesota DOC has
10 historically relied on the Constant Growth DCF model to estimate a forward-
11 looking market return for the CAPM, and that market return has been considered
12 by the Minnesota Public Utilities Commission (“Minnesota PUC”) in prior
13 proceedings.⁴³

14 **Q. How does the current expected market return of 14.13 percent compare to**
15 **observed historical market returns?**

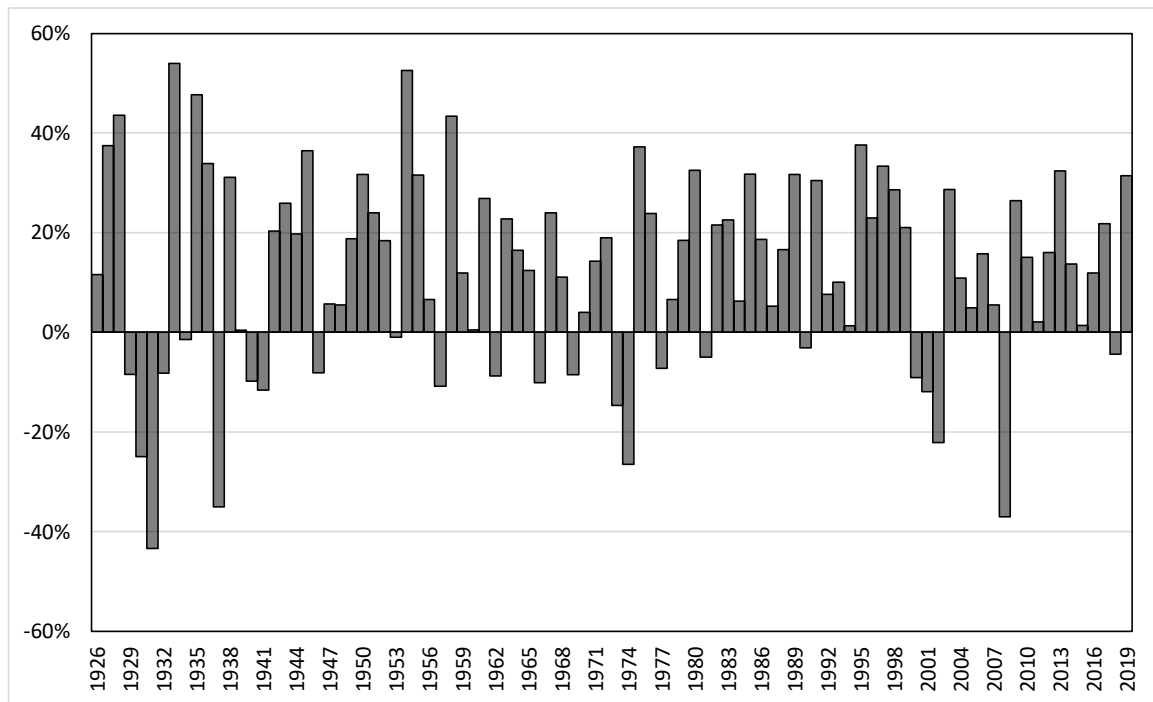
16 A. Given the range of annual equity returns that have been observed over the past 94
17 years (shown in Figure 7 below), a current expected return of 14.13 percent is not
18 unreasonable. In 47 of the past 94 years (i.e., in approximately half of all
19 observations), the realized total equity return was at least 14.13 percent or greater.

⁴² Docket No. G-004/GR-19-511, In the Matter of the Petition By Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., for Authority to Increase Natural Gas Rates in Minnesota (March 3, 2020), at Ex. DER-9, CMA-S-8.

⁴³ See Docket No. E017/GR-15-1033, Findings of Fact, Conclusions and Order, May 1, 2017, at 54-56; and Docket No. E015/GR-16-664, Findings of Fact, Conclusions and Order, March 12, 2018, at 60-61.

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Figure 7: Realized U.S. equity market returns (1926-2019) ⁴⁴



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

A. Yes, I did. I have also considered the results of an Empirical CAPM (“ECAPM”)⁴⁵ in estimating the cost of equity for MGUC. The ECAPM calculates the product of the adjusted Beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Where:

⁴⁴ Depicts total annual returns on large company stocks, as reported in the 2020 Duff & Phelps SBBI Yearbook.

⁴⁵ See *e.g.*, Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

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1 k_e = the market-required ROE of an individual security

2 β = Adjusted Beta coefficient of an individual security

3 r_f = the risk-free rate of return

4 r_m = the market-required return on the equity market as a whole

5 In essence, the Empirical form of the CAPM addresses the tendency of the
6 “traditional” CAPM to underestimate the cost of equity for companies with low
7 Beta coefficients, such as regulated utilities. In that regard, the ECAPM is not
8 redundant to the use of adjusted Betas; rather, it recognizes the results of academic
9 research indicating that the risk-return relationship is different (in essence, flatter)
10 than estimated by the CAPM, and that the CAPM underestimates the “alpha,” or
11 the constant return term.⁴⁶

12 As with the CAPM, my application of the ECAPM uses the forward-looking market
13 risk premium estimates, the three yields on 30-year Treasury securities noted earlier
14 as the risk-free rate, and the Bloomberg, Value Line and long-term average Beta
15 coefficients.

16 **Q. What are the results of your CAPM and ECAPM analyses?**

17 A. As shown in Figure 8 below, my traditional CAPM analysis produces a range of
18 returns from 10.68 percent to 12.67 percent. The ECAPM analysis results range
19 from 11.54 percent to 13.04 percent.

⁴⁶ *Id.* at 191.

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Figure 8: CAPM and ECAPM Results

	Current Risk-Free Rate (1.77%)	Q2 2021–Q2 2022 Projected Risk-Free Rate (2.06%)	2022-2026 Projected Risk-Free Rate (2.80%)
CAPM			
Value Line Beta	12.54%	12.58%	12.67%
Bloomberg Beta	11.59%	11.65%	11.80%
Long-term Avg. Beta	10.68%	10.76%	10.97%
ECAPM			
Value Line Beta	12.94%	12.96%	13.04%
Bloomberg Beta	12.23%	12.27%	12.38%
Long-term Avg. Beta	11.54%	11.60%	11.76%

Bond Yield Plus Risk Premium Analysis

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

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for natural gas utility companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely

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1 related to the level of interest rates. That is, as interest rates increase (decrease),
2 the equity risk premium decreases (increases). Consequently, it is important to
3 develop an analysis that: (1) reflects the inverse relationship between interest rates
4 and the equity risk premium; and (2) relies on recent and expected market
5 conditions. Such an analysis can be developed based on a regression of the risk
6 premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for
7 natural gas utilities serve as the measure of required equity returns and define the
8 yield on the long-term U.S. Treasury bond as the relevant measure of interest rates,
9 the risk premium simply would be the difference between those two points.⁴⁷

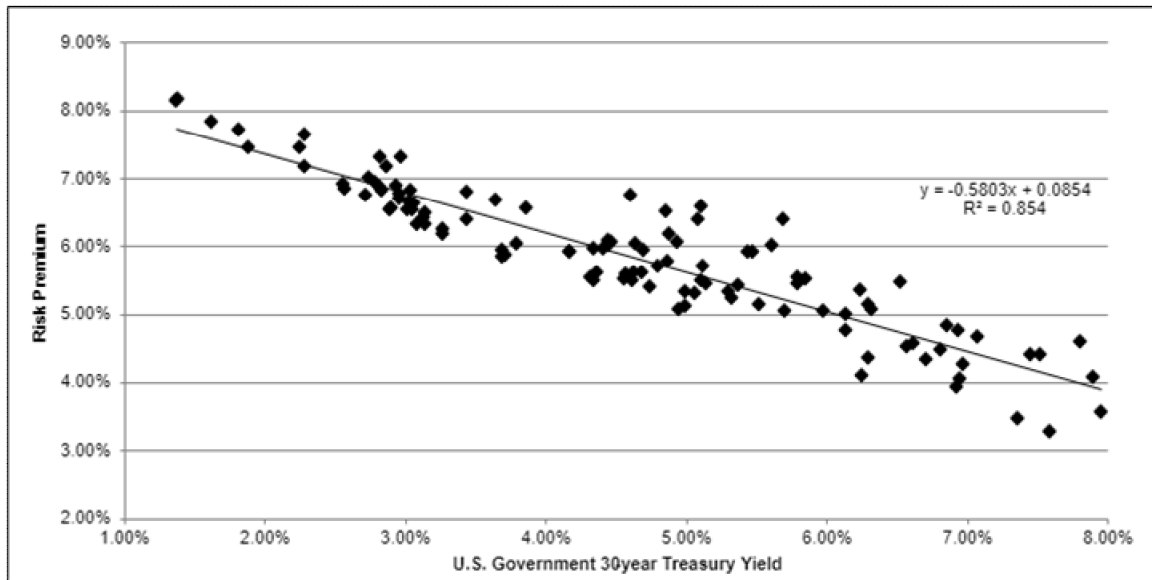
10 **Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?**

11 A. Yes, it is. Investors are aware of ROE awards in other jurisdictions, and they
12 consider those awards as a benchmark for a reasonable level of equity returns for
13 utilities of comparable risk operating in other jurisdictions. Because my Bond
14 Yield Plus Risk Premium analysis is based on authorized ROEs for utility
15 companies relative to corresponding Treasury yields, it provides relevant
16 information to assess the return expectations of investors.

⁴⁷ See e.g., S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. See also Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

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Figure 9: Utility Equity Risk Premium Regression Model



As shown on Schedule D15, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 1.77 percent), the risk premium would be 7.51 percent, resulting in an estimated ROE of 9.28 percent. Based on the near-term (Q2 2021–Q2 2022) projections of the 30-year U.S. Treasury bond yield (i.e., 2.06 percent), the risk premium would be 7.34 percent, resulting in an estimated ROE of 9.40 percent. Based on longer-term (2022-2026) projections of the 30-year U.S. Treasury bond yield (i.e., 2.80 percent), the risk premium would be 6.91 percent, resulting in an estimated ROE of 9.71 percent.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for MGUC?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for MGUC. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium

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1 analysis takes into account this comparison by estimating the return expectations
2 of investors based on the current and past ROE awards of natural gas utilities across
3 the US.

4 **VIII. REGULATORY AND BUSINESS RISKS**

5 **Q. Do the DCF, CAPM, and ECAPM results for the proxy group, taken alone,**
6 **provide an appropriate estimate of the cost of equity for MGUC?**

7 A. No. These results provide only a range of the appropriate estimate of the
8 Company's cost of equity. There are several additional factors that must be taken
9 into consideration when determining where the Company's cost of equity falls
10 within the range of results. These factors, which are discussed below, should be
11 considered with respect to their overall effect on the Company's risk profile.

12 **Small Size Risk**

13 **Q. Please explain the risk associated with small size.**

14 A. Both the financial and academic communities have long accepted the proposition
15 that the cost of equity for small firms is subject to a "size effect." While empirical
16 evidence of the size effect often is based on studies of industries other than
17 regulated utilities, utility analysts also have noted the risk associated with small
18 market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

19 For small utilities, investors face additional obstacles, such as
20 a smaller customer base, limited financial resources, and a lack
21 of diversification across customers, energy sources, and
22 geography. These obstacles imply a higher investor return.⁴⁹

⁴⁹ Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

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1 **Q. How does the smaller size of a utility affect its business risk?**

2 A. In general, smaller companies are less able to withstand adverse events that affect
3 their revenues and expenses. The impact of weather variability, the loss of large
4 customers to bypass opportunities, or the destruction of demand as a result of
5 general macroeconomic conditions or fuel price volatility will have a
6 proportionately greater impact on the earnings and cash flow volatility of smaller
7 utilities. Similarly, capital expenditures for non-revenue producing investments,
8 such as system maintenance and replacements, will put proportionately greater
9 pressure on customer costs, potentially leading to customer attrition or demand
10 reduction. Taken together, these risks affect the equity return required by investors
11 in smaller companies.

12 **Q. How does MGUC's natural gas distribution operations in Michigan compare**
13 **in size to the proxy group companies?**

14 A. As noted previously, MGUC serves approximately 180,000 customers and, as of
15 year-end 2019, had net utility natural gas plant in Michigan of approximately \$290
16 million. MGUC's natural gas distribution operations in Michigan are substantially
17 smaller than the median for the proxy group companies in terms of market
18 capitalization. Schedule D16 provides the actual market capitalization for the
19 proxy group companies and estimates the implied market capitalization for MGUC
20 (i.e., the implied market capitalization if MGUC's natural gas distribution
21 operations in Michigan were a stand-alone publicly traded entity). To estimate the
22 size of the Company's market capitalization relative to the proxy group, I calculated
23 MGUC's proposed capital structure equity component of \$170.38 million by

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1 multiplying MGUC's projected 2022 rate base of \$324.53 million by MGUC's
2 projected test year common equity ratio of 52.50 percent. I then applied the median
3 market-to-book ratio for the proxy group of 1.60 to MGUC's implied common
4 equity balance and arrived at an implied market capitalization of approximately
5 \$273.43 million, or 8.06 percent of the median market capitalization for the proxy
6 group.

7 **Q. How did you estimate the size premium for MGUC?**

8 A. Given this relative size information, it is possible to estimate the impact of size on
9 the ROE for MGUC using Duff & Phelps data that estimates the stock risk premia
10 based on the size of a company's market capitalization. As shown in Schedule D16,
11 the median market capitalization of the proxy group of approximately \$3.39 billion
12 corresponds to the *fifth* decile of the Duff & Phelps market capitalization data.
13 Based on Duff & Phelps' analysis, that decile corresponds to a size premium of
14 1.08 percent. Meanwhile, MGUC's implied market capitalization of approximately
15 \$273.43 million falls within the *ninth* decile, which comprises market capitalization
16 levels up to \$515.60 million and corresponds to a size premium of 2.26 percent.
17 The difference between those size premia is 118 basis points (i.e., 2.26 percent
18 minus 1.08 percent, with rounding).

19 **Q. Were utility companies included in the size premium study conducted by Duff**
20 **and Phelps?**

21 A. Yes. In fact, as shown in Exhibit 7.2 of Duff and Phelps' 2019 Valuation
22 Handbook, OGE Energy Corp. had the largest market capitalization of the

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1 companies contained in the fourth decile.⁵⁰ Therefore, Duff and Phelps did include
2 utility companies in its size risk premium study.

3 **Q. Is the size premium applicable to companies in regulated industries such as**
4 **natural gas utilities?**

5 A. Yes, it is. In fact, Stéphane Chrétien and Frank Coggins in the article “Cost of
6 Equity for Energy Utilities: Beyond the CAPM”,⁵¹ recently studied the CAPM and
7 its ability to estimate the risk premium for the utility industry in particular
8 subgroups of utilities. One of the subgroups was a group of natural gas distribution
9 companies that contained many of the same natural gas distribution companies
10 included in my proxy group.⁵² The article considered the CAPM, the Fama-French
11 three-factor model and a model similar to the ECAPM that I have also considered
12 above. In the article, the Fama-French three-factor model explicitly included an
13 adjustment to the CAPM for risk associated with size. As Chrétien and Coggins
14 show the Beta coefficient on the size variable for the U.S. natural gas utility group
15 was positive and statistically significant indicating that small size risk was relevant
16 for regulated natural gas utilities.⁵³ This demonstrates that the traditional CAPM
17 model would not account for risk associated with small size.

⁵⁰ Duff & Phelps, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

⁵¹ Chrétien, Stéphane, and Frank Coggins. “Cost Of Equity For Energy Utilities: Beyond The CAPM.” Energy Studies Review, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531.

⁵² The U.S. natural gas utility group included: AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc.

⁵³ Chrétien, Stéphane, and Frank Coggins. “Cost Of Equity For Energy Utilities: Beyond The CAPM.” Energy Studies Review, vol. 18, no. 2, 2011, doi:10.15173/esr.v18i2.531, at 31.

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1 **Q. Have regulators in other jurisdictions made a specific risk adjustment to the**
2 **ROE results based on a company’s small size?**

3 A. Yes, they have. In Order No. 15, the Regulatory Commission of Alaska (“RCA”)
4 concluded that Alaska Electric Light and Power Company (“AEL&P”) was riskier
5 than the proxy group companies due to small size as well as other business risks.
6 The RCA did “not believe that adopting the upper end of the range of ROE analyses
7 in this case, without an explicit adjustment, would adequately compensate AEL&P
8 for its greater risk.”⁵⁴ Thus, the RCA awarded AEL&P an ROE of 12.875 percent
9 which was 108 basis points above the highest return on equity estimate from any
10 model presented in the case.⁵⁵ Similarly, in Order No. 19, the RCA noted that small
11 size as well as other business risks such as structural regulatory lag, weather risk,
12 alternative rate mechanisms, gas supply risk, geographic isolation and economic
13 conditions increased the risk of ENSTAR Natural Gas Company.⁵⁶ Ultimately, the
14 RCA concluded that:

15 Although we agree that the risk factors identified by ENSTAR
16 increase its risk, we do not attempt to quantify the amount of
17 that increase. Rather, we take the factors into consideration
18 when evaluating the remainder of the record and the
19 recommendations presented by the parties. After applying our
20 reasoned judgment to the record, we find that 11.875%
21 represents a fair ROE for ENSTAR.⁵⁷

⁵⁴ Docket No. U-10-29, In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company, Order entered September 2, 2011 (Order No. 15), at 37.

⁵⁵ *Id.* at 32 and 37.

⁵⁶ Docket No. U-16-066, In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of SEMCO Energy, Inc., Order entered September 22, 2017 (Order No. 19), at 50-52.

⁵⁷ *Id.*

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1 Additionally, in Docket No. E017/GR-15-1033 for Otter Tail Power Company
2 (“Otter Tail”), the Minnesota PUC selected an ROE above the mean DCF results,
3 due to multiple factors—one of which was Otter Tail’s small size. The Minnesota
4 PUC stated:

5 The record in this case establishes a compelling basis for
6 selecting an ROE above the mean average within the DCF
7 range, given Otter Tail’s unique characteristics and
8 circumstances relative to other utilities in the proxy group.
9 These factors include the company’s relatively smaller size,
10 geographically diffuse customer base, and the scope of the
11 Company’s planned infrastructure investments.⁵⁸

12 Finally, in Opinion No. 569 and 569-A, the FERC has relied on a size premium
13 adjustment in its CAPM estimates for electric utilities. In those decisions, the
14 FERC noted that “the size adjustment was necessary to correct for the CAPM’s
15 inability to fully account for the impact of firm size when determining the cost of
16 equity”.⁵⁹

17 **Q. How have you considered the smaller size of MGUC in your recommendation?**

18 A. While I have estimated the effect of MGUC’s small size on its cost of equity, I am
19 not proposing a specific adjustment to my analytical results for this risk factor.
20 Rather, I believe it is important to consider the small size of MGUC’s natural gas
21 distribution operations in Michigan in the determination of where, within the
22 overall range of analytical results, the Company’s cost of equity falls. I believe that
23 the additional risk associated with small size indicates that the Company’s

⁵⁸ Order in Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (August 16, 2016), at 55.

⁵⁹ Federal Energy Regulatory Commission, Opinion No. 569-A, May 21, 2020, at para 75.

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1 authorized ROE should be set above the mean analytical results for the proxy group
2 companies.

3 **Capital Expenditures**

4 **Q. Please summarize the Company's capital expenditure requirements.**

5 A. The Company's current projections for 2021 through 2025 include approximately
6 \$235 million in capital investments for the period.⁶⁰ These anticipated capital
7 expenditures equate to approximately 81 percent of MGUC's 2019 net utility plant.

8 **Q. How is the Company's risk profile affected by its substantial capital**
9 **expenditure requirements?**

10 A. As with any utility faced with substantial capital expenditure requirements, the
11 Company's risk profile may be adversely affected in two significant and related
12 ways: (1) the heightened level of investment increases the risk of under-recovery
13 or delayed recovery of the invested capital; and (2) an inadequate return would put
14 downward pressure on key credit metrics.

15 **Q. Do credit rating agencies recognize the risks associated with elevated levels of**
16 **capital expenditures?**

17 A. Yes, they do. From a credit perspective, the additional pressure on cash flows
18 associated with high levels of capital expenditures exerts corresponding pressure
19 on credit metrics and, accordingly, on credit ratings. To that point, S&P explains
20 the importance of regulatory support for large capital projects:

⁶⁰ Data provided by Company.

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1 When applicable, a jurisdiction's willingness to support large
2 capital projects with cash during construction is an important
3 aspect of our analysis. This is especially true when the project
4 represents a major addition to rate base and entails long lead
5 times and technological risks that make it susceptible to
6 construction delays. Broad support for all capital spending is
7 the most credit-sustaining. Support for only specific types of
8 capital spending, such as specific environmental projects or
9 system integrity plans, is less so, but still favorable for
10 creditors. Allowance of a cash return on construction work-
11 in-progress or similar ratemaking methods historically were
12 extraordinary measures for use in unusual circumstances, but
13 when construction costs are rising, cash flow support could be
14 crucial to maintain credit quality through the spending
15 program. Even more favorable are those jurisdictions that
16 present an opportunity for a higher return on capital projects
17 as an incentive to investors.⁶¹

18 Therefore, to the extent that MGUC's rates do not permit the opportunity to recover
19 its capital investments on a regular basis, the Company will face increased recovery
20 risk and thus increased pressure on its credit metrics.

21 **Q. How do MGUC's capital expenditure requirements compare to those of the**
22 **proxy group companies?**

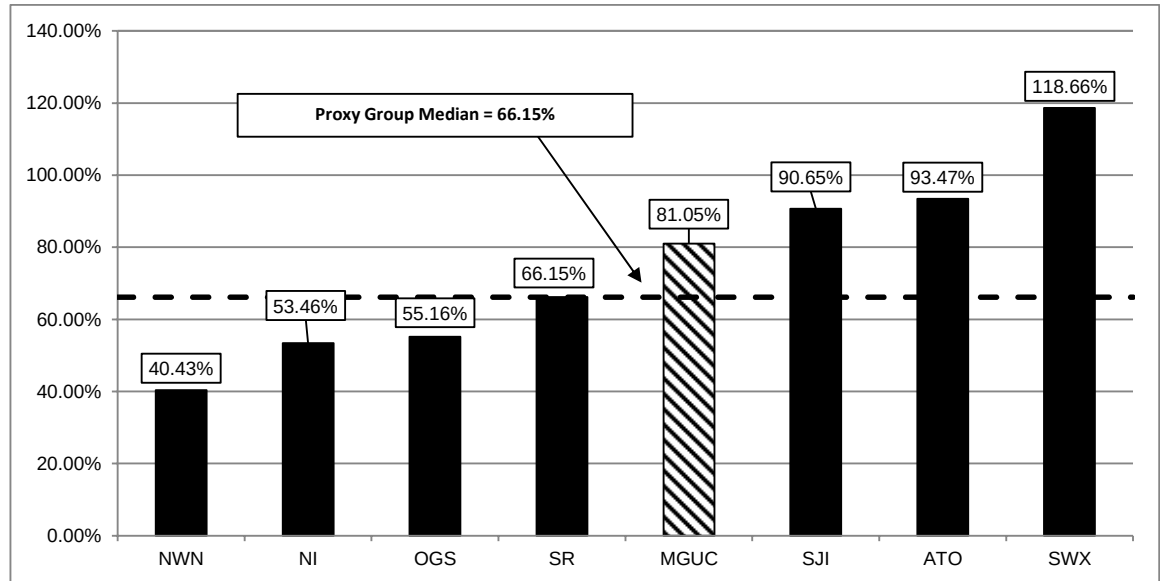
23 A. As shown in Schedule D17, I calculated the ratio of expected capital expenditures
24 to net utility plant for MGUC and each of the companies in the proxy group by
25 dividing each company's projected capital expenditures for the period from 2021-
26 2025 by its total net utility plant as of December 31, 2019. As shown in Schedule
27 D17 (see also Figure 10 below), MGUC's ratio of capital expenditures as a
28 percentage of net utility plant is 81.05 percent, which is approximately 1.23 times

⁶¹ S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

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the median for the proxy group companies of 66.15 percent. This result indicates a risk level for MGUC that is slightly greater than the companies in the proxy group.

Figure 10: Comparison of Capital Expenditures – Proxy Group Companies



Q. Does MGUC currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. No, it does not. However, MGUC is proposing a Main Replacement Program (“MRP”) surcharge rider to recover the costs associated with qualifying gas infrastructure investments. It is important to note that the majority of the costs included in MGUC’s capital expenditures plan do not qualify for cost recovery through the MRP. In fact, the MRP represents only approximately 13 percent of projected capital expenditures for 2023-2027. As a result, MGUC may still depend on rate case filings for the majority of its capital cost recovery even if the MRP was approved by the Commission.

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1 Additionally, as shown in Schedule D18, 76 percent of the proxy group utilities
2 recover costs through capital tracking mechanisms. While MGUC would recover
3 a portion of its capital expenditures through the MRP if approved, the Company
4 would still potentially rely on rate case filings for a large portion of its capital costs.
5 Moreover, if MGUC were not allowed to recover its qualifying gas infrastructure
6 investments through a capital tracking mechanism, its risk relative to the proxy
7 group would be increased.

8 **Q. What are your conclusions regarding the effect of the Company's capital**
9 **spending requirements on its risk profile and cost of capital?**

10 A. The Company's capital expenditure requirements are significant and will continue
11 over the next few years. Although MGUC has proposed an MRP to recover a
12 portion of these expenditures, the majority of operating subsidiaries held by the
13 proxy group also have a capital tracking mechanism, meaning that this risk
14 mitigation is already reflected in the proxy group companies. Further, a large
15 portion of MGUC's capital expenditures do not qualify for recovery through the
16 MRP; as such, the Company would still depend on rate case filings to recover the
17 majority of its capital expenditures even if the MRP is approved. My conclusion is
18 that MGUC's significant capital expenditure plan, only part of which would qualify
19 for timely cost recovery if the MRP was approved, results in a risk profile that is
20 greater than that of the proxy group and supports an ROE toward the higher end of
21 the reasonable range of ROEs.

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1 **Regulatory Risk**

2 **Q. Please explain how the regulatory environment affects investors' risk**
3 **assessments.**

4 A. The ratemaking process is premised on the principle that, for investors and
5 companies to commit the capital needed to provide safe and reliable utility service,
6 the subject utility must have the opportunity to recover the return of, and the
7 market-required return on, invested capital. Regulatory authorities recognize that
8 because utility operations are capital intensive, regulatory decisions should enable
9 the utility to attract capital at reasonable terms; doing so balances the long-term
10 interests of investors and customers. Utilities must finance their operations and
11 require the opportunity to earn a reasonable return on their invested capital to
12 maintain their financial profiles. MGUC is no exception. In that respect, the
13 regulatory environment is one of the most important factors considered in both debt
14 and equity investors' risk assessments.

15 From the perspective of debt investors, the authorized return should enable the
16 utility to generate the cash flow needed to meet its near-term financial obligations,
17 make the capital investments needed to maintain and expand its systems, and
18 maintain the necessary levels of liquidity to fund unexpected events. This financial
19 liquidity must be derived not only from internally generated funds, but also by
20 efficient access to capital markets. Moreover, because fixed income investors have
21 many investment alternatives, even within a given market sector, the utility's
22 financial profile must be adequate on a relative basis to ensure its ability to attract
23 capital under a variety of economic and financial market conditions.

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1 Equity investors require that the authorized return be adequate to provide a risk-
2 comparable return on the equity portion of the utility's capital investments.
3 Because equity investors are the residual claimants on the utility's cash flows
4 (which is to say that the equity return is subordinate to interest payments), they are
5 particularly concerned with the strength of regulatory support and its effect on
6 future cash flows.

7 **Q. Please explain how credit rating agencies consider regulatory risk in**
8 **establishing a company's credit rating.**

9 A. Both S&P and Moody's consider the overall regulatory framework in establishing
10 credit ratings. Moody's establishes credit ratings based on four key factors: (1)
11 regulatory framework; (2) the ability to recover costs and earn returns; (3)
12 diversification; and (4) financial strength, liquidity, and key financial metrics. Of
13 these criteria, regulatory framework, and the ability to recover costs and earn
14 returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's
15 assigns regulatory risk a 50.00 percent weighting in the overall assessment of
16 business and financial risk for regulated utilities.⁶²

17 S&P also identifies the regulatory framework as an important factor in credit ratings
18 for regulated utilities, stating: "One significant aspect of regulatory risk that
19 influences credit quality is the regulatory environment in the jurisdictions in which
20 a utility operates."⁶³ S&P identifies four specific factors that it uses to assess the

⁶² Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

⁶³ Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

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1 credit implications of the regulatory jurisdictions of investor-owned regulated
2 utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3)
3 financial stability; and (4) regulatory independence and insulation.⁶⁴

4 **Q. How does the regulatory environment in which a utility operates affect its**
5 **access to and cost of capital?**

6 A. The regulatory environment can significantly affect both the access to, and cost of
7 capital in several ways. First, the proportion and cost of debt capital available to
8 utility companies are influenced by the rating agencies' assessment of the
9 regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which
10 typically operate as a monopoly, the regulatory environment and how the utility
11 adapts to that environment are the most important credit considerations."⁶⁵
12 Moody's further highlighted the relevance of a stable and predictable regulatory
13 environment to a utility's credit quality, noting: "[b]roadly speaking, the
14 Regulatory Framework is the foundation for how all the decisions that affect
15 utilities are made (including the setting of rates), as well as the predictability and
16 consistency of decision-making provided by that foundation."⁶⁶

⁶⁴ *Id.*, at 1.

⁶⁵ Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

⁶⁶ *Id.*

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1 **Q. Have you conducted any analysis of the regulatory framework in Michigan**
2 **relative to the jurisdictions in which the companies in your proxy group**
3 **operate?**

4 A. Yes. I have evaluated the regulatory framework in Michigan on three factors that
5 are important in terms of providing a regulated utility an opportunity to earn its
6 authorized ROE. These are: (1) test year convention (i.e., forecast vs. historical);
7 (2) method for determining rate base (i.e., average vs. year-end); and (3) prevalence
8 of capital cost recovery between rate cases. The results of this regulatory risk
9 assessment are shown in Schedule D18. As shown in Schedule D18, while MGUC
10 utilizes a projected test year and is proposing a capital tracking mechanism, the
11 Company calculates rate base based on average original cost. Therefore, many of
12 the operating subsidiaries of the proxy group companies have more timely cost
13 recovery through forecasted test years, year-end rate base, and cost recovery
14 trackers than MGUC has in Michigan. Furthermore, it is important to note that
15 MGUC's regulatory risk relative to the proxy group would increase if the proposed
16 capital tracking mechanism is not approved by the Commission.

17 **Q. What are your conclusions regarding the perceived risks related to the**
18 **Michigan regulatory environment?**

19 A. As discussed throughout this section of my testimony, both Moody's and S&P have
20 identified the supportiveness of the regulatory environment as an important
21 consideration in developing their overall credit ratings for regulated utilities.
22 Considering the regulatory adjustment mechanisms, many of the companies in the
23 proxy group have more timely cost recovery than MGUC has in Michigan.

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1 Therefore, the estimated proxy group COE would understate the return on equity
2 that an investor would require in Michigan because the risks of timely and full cost
3 recovery are greater for MGUC in Michigan than for the proxy group.

4 **Flotation Costs**

5 **Q. What are flotation costs?**

6 A. Flotation costs are the costs associated with the sale of new issues of common stock.
7 These costs include out-of-pocket expenditures for preparation, filing, and
8 underwriting, and other issuance costs.

9 **Q. Why is it important to consider flotation costs in the allowed ROE?**

10 A. A regulated utility must have the opportunity to earn an ROE that is both
11 competitive and compensatory to attract and retain new investors. To the extent
12 that a company is denied the opportunity to recover prudently incurred flotation
13 costs, realized returns will fall short of expected returns, thereby diluting equity
14 share value.

15 **Q. Are flotation costs part of the utility's invested costs or part of the utility's**
16 **expenses?**

17 A. Flotation costs are part of the invested costs of the utility, which are properly
18 reflected on the balance sheet under "paid-in capital." They are not current
19 expenses, and, therefore, are not reflected on the income statement. Rather, like
20 investments in rate base or the issuance costs of long-term debt, flotation costs are
21 incurred over time. As a result, the great majority of a utility's flotation cost is
22 incurred prior to the test year but remains part of the cost structure that exists during

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1 the test year and beyond—and, as such, should be recognized for ratemaking
2 purposes. Therefore, whether an issuance occurs during the test year or is planned
3 for the test year is irrelevant, because failure to allow recovery of past flotation
4 costs may deny MGUC the opportunity to earn its market-required ROE in the
5 future.

6 **Q. Please provide an example of why a flotation cost adjustment is necessary to**
7 **compensate investors for the capital they have invested.**

8 A. Suppose WEC issues stock with a value of \$100, and an equity investor invests
9 \$100 in WEC in exchange for that stock. Further suppose that, after paying the
10 flotation costs associated with the equity issuance, which include fees paid to
11 underwriters and attorneys, among others, WEC ends up with only \$97 of issuance
12 proceeds, rather than the \$100 the investor contributed. WEC invests that \$97 in
13 plant used to serve its customers, which becomes part of rate base. Absent a
14 flotation cost adjustment, the investor will thereafter earn a return on only the \$97
15 invested in rate base, even though she contributed \$100. Making a small flotation
16 cost adjustment gives the investor a reasonable opportunity to earn the authorized
17 return, rather than the lower return that results when the authorized return is applied
18 to an amount less than what the investor contributed.

19 **Q. Is the date of WEC's last issuance of common equity important in the**
20 **determination of flotation costs?**

21 A. No, it is not. Prior to its acquisition by WEC, Integrys had two equity issuances.
22 As shown in Schedule D19, Integrys closed on equity issuances of approximately
23 \$173 million and \$102 million (for a total of 5.9 million shares of common stock)

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1 in November 2003 and November 2005, respectively. The vintage of the issuance,
2 however, is not particularly important because the investor suffers a shortfall in
3 every year that he should have a reasonable opportunity to earn a return on the full
4 amount of capital that he has contributed. Returning to my earlier example, the
5 investor who contributed \$100 is entitled to a reasonable opportunity to earn a
6 return on \$100 not only in the first year after the investment, but in every subsequent
7 year in which he has the \$100 invested. Leaving aside depreciation, which is dealt
8 with separately, there is no basis to conclude that the investor is entitled to earn a
9 return on \$100 in the first year after issuance, but thereafter is entitled to earn a
10 return on only \$97. As long as the \$100 is invested, the investor should have a
11 reasonable opportunity to earn a return on the entire amount.

12 **Q. Is the need to consider flotation costs eliminated because MGUC is a wholly**
13 **owned subsidiary of WEC?**

14 A. No, it is not. Although MGUC is a wholly owned subsidiary of WEC, it is
15 appropriate to consider flotation costs. Wholly owned subsidiaries receive equity
16 capital from their parent and provide returns on the capital that roll up to the parent,
17 which is designated to attract and raise capital based upon the returns of those
18 subsidiaries. To deny recovery of issuance costs associated with the capital that is
19 invested in the subsidiaries ultimately penalizes the investors that fund utility
20 operations and inhibits the utility's ability to obtain new equity capital at a
21 reasonable cost. This is particularly important for MGUC because, as I discuss in
22 more detail below, it is planning significant capital expenditures in the near term.

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1 **Q. Is the need to consider flotation costs recognized by the academic and financial**
2 **communities?**

3 A. Yes, it is. The need to reimburse shareholders for the lost returns associated with
4 equity issuance costs is recognized by the academic and financial communities in
5 the same spirit that investors are reimbursed for the costs of issuing debt. This
6 treatment is consistent with the philosophy of a fair ROR. According to Dr.
7 Shannon Pratt:

8 Flotation costs occur when new issues of stock or debt are sold
9 to the public. The firm usually incurs several kinds of flotation
10 or transaction costs, which reduce the actual proceeds received
11 by the firm. Some of these are direct out-of-pocket outlays,
12 such as fees paid to underwriters, legal expenses, and
13 prospectus preparation costs. Because of this reduction in
14 proceeds, the firm's required returns on these proceeds equate
15 to a higher return to compensate for the additional costs.
16 Flotation costs can be accounted for either by amortizing the
17 cost, thus reducing the cash flow to discount, or by
18 incorporating the cost into the cost of capital. Because
19 flotation costs are not typically applied to operating cash flow,
20 one must incorporate them into the cost of capital.⁶⁷

21 **Q. What is the effect of flotation costs on MGUC's COE?**

22 A. My flotation cost calculation is based on the costs of issuing equity that were
23 incurred by WEC in its two most recent common equity issuances. As shown in
24 Schedule D19, based on the costs of those two issuances, the impact on the proxy
25 group's COE amounts to approximately 0.15 percent (i.e., 15 basis points).

⁶⁷ Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-21.

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1 **Q. Do your final results include an adjustment for flotation cost recovery?**

2 A. No, they do not. I did not make an explicit adjustment for flotation costs to any of
3 my quantitative results. Rather, I am providing the flotation cost argument and
4 calculation as additional support for my recommended ROE of 10.20 percent, and
5 for where that recommendation falls within the range of results produced by my
6 Constant Growth DCF, Multi-Stage DCF, CAPM, ECAPM, and Risk Premium
7 analyses.

8 **IX. CAPITAL STRUCTURE**

9 **Q. Is the capital structure of the Company an important consideration in the**
10 **determination of the appropriate ROE?**

11 A. Yes, it is. Assuming other factors equal, a higher debt ratio increases the risk to
12 investors. For debt holders, higher debt ratios result in a greater portion of the
13 available cash flow being required to meet debt service, thereby increasing the risk
14 associated with the payments on debt. The result of increased risk is a higher
15 interest rate. The incremental risk of a higher debt ratio is more significant for
16 common equity shareholders, who are the residual claimants on the cash flow of
17 the Company. Therefore, the greater the debt service requirement, the less cash
18 flow is available for common equity holders.

19 **Q. What is MGUC's proposed capital structure?**

20 A. MGUC is proposing a rate-making capital structure composed of 52.50 percent
21 common equity and 47.50 percent long-term debt.

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1 **Q. Have you conducted any analysis to determine if the proposed equity ratio is**
2 **reasonable?**

3 A. Yes, I have. I reviewed MGUC's proposed capital structure as compared to the
4 capital structures of the utility operating subsidiaries of the proxy companies.
5 Because the authorized ROE is set based on analysis of a risk-comparable proxy
6 group, it is reasonable to consider the proxy group average capital structure as a
7 benchmark for the Company's proposed equity ratio.

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

10 A. I calculated the mean proportions of common equity, long-term debt, and preferred
11 equity for the most recent year for each of the companies in the proxy group at the
12 operating subsidiary level.⁶⁸ As shown in Schedule D20, the mean common equity
13 ratio for operating subsidiaries of the proxy group companies was 55.35 percent
14 (representing a range of 48.52 percent to 63.38 percent). MGUC's proposed equity
15 ratio of 52.50 percent is towards the low-end of the range of equity ratios for the
16 utility operating subsidiaries of the proxy group companies and is therefore
17 reasonable.

18 **Q. Are there other factors to be considered in setting the Company's capital**
19 **structure?**

20 A. Yes, there are. The credit rating agencies' response to the TCJA must also be
21 considered when determining the equity ratio. All three rating agencies have noted

⁶⁸ Long-term debt includes the current portion of long-term debt, assuming that the current portion would be refinanced with debt at maturity.

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1 that the TCJA has negative implications for utility cash flows. And S&P and Fitch
2 have specifically identified increasing the equity ratio as one approach to ensure
3 that utilities have sufficient cash flows following the tax cuts and the loss of bonus
4 depreciation. As S&P noted, “[r]egulators must also recognize that tax reform is a
5 strain on utility credit quality, and we expect companies to request stronger capital
6 structures and other means to offset some of the negative impact”.⁶⁹ Furthermore,
7 Moody’s downwardly revised the rating outlook for the entire utilities sector in
8 June 2018 and (as shown in 5 in Section V of my Direct Testimony) has continued
9 to downgrade the ratings of utilities based in part on the negative effects of the
10 TCJA on cash flows. In 2018, Moody’s downgraded WEC’s credit rating from A3
11 to Baa1; and Moody’s also noted that its “stable” outlook for WEC was contingent
12 upon the regulatory environments of its subsidiaries remaining credit supportive.⁷⁰

13 Additionally, it is also important to consider the negative effects of COVID-19 on
14 the credit metrics of utilities. As discussed in Section V above, Standard & Poor’s
15 recently downwardly revised the outlook on the entire North American utilities
16 sector and noted that COVID-19 would create incremental pressure on credit
17 metrics and that a recession would lead to an increasing number of credit rating
18 downgrades and negative outlooks. As a result, the credit ratings agencies’
19 continued concerns over the negative effects of the TCJA, coupled with concern
20 over the negative effects of COVID-19, underscores the importance of maintaining

⁶⁹ Standard & Poor’s Ratings, “U.S. Tax Reform: For Utilities’ Credit Quality, Challenges Abound”, January 24, 2018, at 5.

⁷⁰ Moody’s Investors Service, Rating Action: Moody’s downgrades WEC Energy, Wisconsin Energy Capital and Integrys to Baa1 from A3; stable outlook, July 12, 2018.

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1 adequate cash flow metrics for the industry—and for MGUC, in the context of this
2 proceeding.

3 **Q. Is there a relationship between the equity ratio and the authorized ROE?**

4 A. Yes, there is. The equity ratio is the primary indicator of financial risk for a
5 regulated utility such as MGUC. To the extent the equity ratio is reduced, it is
6 necessary to increase the authorized ROE to compensate investors for the greater
7 financial risk associated with a lower equity ratio.

8 **Q. What is your conclusion regarding an appropriate equity ratio for MGUC?**

9 A. Considering the actual capital structures of the proxy group operating companies, I
10 believe that MGUC's proposed common equity ratio of 52.50 percent is reasonable.
11 The proposed equity ratio is well within the range of equity ratios established by
12 the capital structures of the utility operating subsidiaries of the proxy companies.
13 Moreover, the credit ratings agencies' continued concern over the negative effects
14 of the TCJA and COVID-19 underscores the importance of maintaining adequate
15 cash flow metrics for the industry—and for MGUC, in the context of this
16 proceeding.

17 **X. CONCLUSION AND RECOMMENDATION**

18 **Q. What is your conclusion regarding a fair ROE for MGUC?**

19 A. Figure 11 below provides a summary of my analytical results. Based on these
20 results, the qualitative analyses presented in my Direct Testimony, the business and
21 financial risks of MGUC compared to the proxy group, and the effects of Federal
22 tax reform and COVID-19 on the cash flow metrics of utilities, it is my view that

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1 an ROE of 10.20 percent is reasonable and would fairly balance the interests of
2 customers and shareholders. This ROE would enable the Company to maintain its
3 financial integrity and therefore its ability to attract capital at reasonable rates under
4 a variety of economic and financial market conditions, while continuing to provide
5 safe, reliable and affordable natural gas utility service to customers in Michigan.

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Figure 11: Summary of Analytical Results

Constant Growth DCF			
	Median Low	Median	Median High
30-Day Average	7.98%	9.92%	12.98%
90-Day Average	7.98%	9.68%	12.71%
180-Day Average	7.94%	9.61%	12.58%
Multi-Stage DCF			
	Median Low	Median	Median High
30-Day Average	9.36%	9.88%	10.76%
90-Day Average	9.09%	9.71%	10.41%
180-Day Average	8.97%	9.44%	10.24%
CAPM			
	Current 30-day Average Treasury Bond Yield (1.77%)	Near-Term Blue Chip Forecast Yield (2.06%)	Long-Term Blue Chip Forecast Yield (2.80%)
Value Line Beta	12.54%	12.58%	12.67%
Bloomberg Beta	11.59%	11.65%	11.80%
Long-term Average Beta	10.68%	10.76%	10.97%
ECAPM			
Value Line Beta	12.94%	12.96%	13.04%
Bloomberg Beta	12.23%	12.27%	12.38%
Long-term Average Beta	11.54%	11.60%	11.76%
Bond Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield (1.77%)	Near-Term Blue Chip Forecast Yield (2.06%)	Long-Term Blue Chip Forecast Yield (2.80%)
Risk Premium Analysis	9.28%	9.40%	9.71%

Q. What is your conclusion with respect to MGUC's proposed capital structure?

A. My conclusion is that MGUC's proposal to establish a capital structure consisting of 52.50 percent common equity, and 47.50 percent long-term debt is reasonable when compared to the capital structures of the companies in the proxy group and taking in consideration the impact of the TCJA on the cash flows and therefore should be adopted.

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- 1 **Q.** **Based Does this conclude your Direct Testimony?**
- 2 **A.** Yes, it does.

ANN E. BULKLEY

Senior Vice President

Ms. Bulkley has more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings. In addition, Ms. Bulkley has worked on acquisition teams with investors seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support. Prior to joining Concentric, Ms. Bulkley held senior expertise-based consulting positions at several firms, including Reed Consulting Group and Navigant Consulting, Inc. where she specialized in valuation. Ms. Bulkley holds an M.A. in economics from Boston University and a B.A. in economics and finance from Simmons College. Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE**Regulatory Analysis and Ratemaking**

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings in which she did not testify.



Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.



Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.

Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

Senior Vice President

Vice President

Assistant Vice President

Project Manager

Navigant Consulting, Inc. (1995 – 2002)

Project Manager

Cahners Publishing Company (1995)

Economist



EDUCATION

Boston University

M.A., Economics, 1995

Simmons College

B.A., Economics and Finance, 1991

CERTIFICATIONS

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Indiana Utility Regulatory Commission				
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No.	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	E018101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	E018060629 G018060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-20718
and for other relief.	)	
_____	)	

DIRECT TESTIMONY AND EXHIBITS OF

AARON L. NELSON

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY AND EXHIBITS OF
AARON L. NELSON

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-20718
and for other relief.	)	
_____	)	

QUALIFICATIONS
OF
AARON L. NELSON
PART I

1 **Q. Please state your name, position, and business address.**

2 A. My name is Aaron L. Nelson. My business address is 231 West Michigan Street,
3 Milwaukee, WI 53203. My position is Sr. Project Specialist–State Regulatory Affairs.
4 I am employed by WEC Business Services, LLC (“WBS”), serving all of the WEC
5 Energy Group, Inc. (“WEC”) utilities, including Michigan Gas Utilities Corporation
6 (“MGUC” or the “Company”). WBS and MGUC are wholly-owned subsidiaries of
7 WEC.

8

9 **Q. For whom are you providing testimony?**

10 A. I am providing testimony on behalf of MGUC.

11

12 **Q. Please describe briefly your educational, professional, and utility background.**

13 A. In 2011, I received a Bachelor of Business Administration degree, with specializations
14 in management and information systems, from the University of Wisconsin–Eau

DIRECT TESTIMONY AND EXHIBITS OF
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1 Claire. In 2016, I received a Master's of Science in Management degree, with
2 specialization in financial analysis, from the University of Wisconsin-Milwaukee. I
3 have completed training courses in public utility regulation at the Michigan State
4 University Institute of Public Utilities.

5 In 2011, I was hired by Wisconsin Electric d/b/a We Energies and worked in various
6 roles in several areas prior to my current role. In 2016, I began working as a Project
7 Specialist in State Regulatory Affairs with WBS. Today, my primary responsibilities
8 include performing cost of service studies and other special studies for all WEC
9 utilities, including MGUC. In addition, I perform and am otherwise involved with rate
10 development and service and tariff administration for WEC's electric and steam
11 utilities.

12

13 **Q. Have you previously testified before any regulatory agency?**

14 A. Yes. I submitted testimony concerning cost of service on behalf of the following: 1)
15 MGUC in Case No. U-20114, 2) Minnesota Energy Resources Corporation, 3) North
16 Shore Gas Company, 4) Wisconsin Electric Power Company's electric, natural gas and
17 steam operations, 5) Wisconsin Gas LLC, and 6) Wisconsin Public Service
18 Corporation's electric and natural gas operations.

DIRECT TESTIMONY AND EXHIBITS OF
AARON L. NELSON

**AARON L. NELSON
DIRECT TESTIMONY
PART II**

1 **Q. What is the purpose of your pre-filed direct testimony?**

2 A. My direct testimony and its attachments describe and present MGUC’s class cost of
3 service study (“COSS”) for the 2022 future test year.

4 MGUC Witness Burzycki’s direct testimony relies in part on the results of the class
5 COSS for the 2022 future test year to develop MGUC’s proposed rate design intended
6 to recover the Company’s base rate revenue requirement.

7

8 **Q. Are you sponsoring any exhibits in this proceeding?**

9 A. Yes, I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-16	F1.1	Cost of service summary by rate class at present rates
A-16	F1.2	Cost of service summary by customer class at present rates
A-16	F1.3	Unbundled revenue requirement by customer class
A-16	F1.4	Unbundled rate base by customer class
A-16	F1.5	Unbundled unit cost by customer class
A-16	F1.6	Cost of service summary by rate class at present rates (alternate 1)

DIRECT TESTIMONY AND EXHIBITS OF
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A-16 F1.7 Cost of service summary by customer
class at present rates (alternate 1)

1

2 These exhibits present the 2022 projected class COSS prepared for MGUC. The
3 accompanying work papers include associated allocation methodologies, supplemental
4 analyses, and data. The following testimony explains these studies.

5

6 **Q. Were these exhibits prepared by you or under your direction?**

7 A. Yes, they were.

8

9 **Q. Can you provide an overview of your testimony and recommendations in this**
10 **proceeding?**

11 A. Yes, below is a summary of my testimony and recommendations:

- 12 1. As stated by MGUC Witness Zgonc in his direct testimony, MGUC's analysis of
13 the test year ending December 31, 2022 indicates a need for an annual rate increase
14 of \$15,127,536, or 10.7% in current revenues from retail gas operations, including
15 the cost of gas. MGUC's class COSS for the 2022 projected test year is based on
16 and uses the components from this analysis;
- 17 2. The customer class revenue requirements as determined by Exhibit A-16, Schedule
18 F1.2 reasonably apportion the Company's proposed revenue increase among rate
19 classes, and should be approved as acceptable guidance for setting rates in this case.

20

21

22

DIRECT TESTIMONY AND EXHIBITS OF
AARON L. NELSON

1 **Q. Please summarize the results of MGUC’s proposed class COSS.**

2 A. Table 1 summarizes the results of MGUC’s class COSS with respect to revenue
3 deficiency at present rates by customer class based on MGUC’s requested revenue
4 requirement consistent with Exhibit A-16, Schedule F1.2. Present rates are those that
5 the Commission approved in MGUC’s most recent rate case, Case No. U-17880 (“2016
6 Rate Case”).

Table 1
Michigan Gas Utilities Corporation
Class Revenue Deficiency at Present Rates

Line Description	Present Revenue \$	Revenue Deficiency \$	Revenue Deficiency %	Revenue Requirement \$
Retail Sales and Transportation				
General Service- Residential	85,644,158	14,536,736	17.0%	100,180,894
Customer Choice- Residential	5,968,608	2,086,282	35.0%	8,054,889
Agg Transport-Residential	7,365	12,482	169.5%	19,847
General Service-Small Customer Choice-GS- Small	32,905,083	(1,453,551)	-4.4%	31,451,532
Agg Transport-GS-Small	3,134,341	(203,561)	-6.5%	2,930,780
Transport-TR-1	1,034,136	94,563	9.1%	1,128,698
General Service-Large Transport-TR-2	2,678,943	(662,320)	-24.7%	2,016,623
Customer Choice-GS- Large	4,428,247	(359,106)	-8.1%	4,069,141
Agg Transport-GS-Large	3,757,984	507,243	13.5%	4,265,227
Transport-TR-3	37,089	(6,590)	-17.8%	30,499
Special Contract	38,688	(8,963)	-23.2%	29,725
Total Jurisdiction	1,297,670	522,302	40.2%	1,819,971
	97,164	62,020	63.8%	159,184
	141,029,474	15,127,536	10.7%	156,157,011

1 Q. How is the remainder of your testimony organized?

9

11 Q. What is the purpose of a class cost of service study?

16

6

DIRECT TESTIMONY AND EXHIBITS OF
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1 the class COSS can be used to determine how costs should be recovered from customer
2 classes through rate design.

3

4 **Q. Please explain the procedures used to develop the class COSS shown in the**
5 **schedules of Exhibit A-16 that you are sponsoring.**

6 A. In general, there are three main steps to determining cost responsibility: 1)
7 functionalization, 2) classification, and 3) allocation. Each of these steps is performed
8 on the Company's total cost of service.

9 Functionalization is the process of categorizing costs based on their function within the
10 utility. Generally, natural gas costs are functionalized either as production, storage,
11 transmission, or distribution.

12 Classification is the process of categorizing costs based on whether they are caused by
13 demand, number of customers, or the commodity consumed.

14 Allocation is the process of apportioning each cost item within each classification and
15 for each function to classes of customers. Some costs, particularly general or indirect
16 costs, cannot be directly functionalized or classified. In general, these costs are
17 allocated to functions, classifications, and customer classes based upon the allocated
18 results of other cost items within the class COSS.

19

20 **Q. What is your process for functionalizing costs?**

21 A. For the most part, the job of functionalizing plant costs is performed by the Plant
22 Accounting Department, which operates in conformance with the Federal Energy
23 Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

DIRECT TESTIMONY AND EXHIBITS OF
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1 Similarly, operations and maintenance (“O&M”) costs are functionalized by our
2 Finance Department, also in conformance with the FERC USOA.

3

4 **Q. What is your process for classifying costs?**

5 A. Once costs are functionalized, all cost elements are classified by whether they are
6 caused by demand, number of customers, or the commodity consumed. Demand-
7 related costs are costs incurred to meet customer demand for natural gas. The cost of
8 a peaking Liquefied Natural Gas (“LNG”) facility is an example of a demand-related
9 cost. Customer-related costs are costs associated with customers regardless of the
10 amount of natural gas they demand or consume. These are costs incurred to extend
11 service to and attach a customer to the distribution system, meter any natural gas usage,
12 and bill and maintain the customer’s account. The cost to install a meter is an example
13 of a customer-related cost. Commodity-related costs are costs incurred as customers
14 consume natural gas. The commodity cost of gas expense is an example of a
15 commodity-related cost. However, when, as is the case with MGUC, a gas utility’s
16 cost of gas is not recovered through its base rates, very little, if any, of its remaining
17 delivery service cost structure is commodity related.

18

19 **Q. What is your process for allocating costs to customer classes?**

20 A. The purpose of cost allocation is to determine cost responsibility by customer class.
21 The prior steps consisting of functionalization and classification facilitate the allocation
22 of costs to customer classes. In general, costs classified as demand-related are allocated
23 to classes based upon a demand allocation factor, costs classified as commodity-related
24 are allocated to classes based upon a commodity allocation factor, and costs classified

DIRECT TESTIMONY AND EXHIBITS OF
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1 as customer-related are allocated to classes based upon a customer allocation factor.
2 Some costs, such as indirect or general costs, closely follow in proportion with other
3 cost items. These costs are allocated using the allocated results of other cost items
4 within the COSS, such as plant in service or the labor portion of O&M expense.
5

6 **Q. Please explain the considerations relied upon in determining the cost allocation**
7 **methodologies that are used to perform a class COSS.**

8 A. As stated earlier, in order to allocate costs within any class COSS, the factors that cause
9 the costs to be incurred must be identified and understood. Additionally, the cost
10 analyst needs to develop data in a form that is compatible with, and supportive of, rate
11 design proposals. The availability of data for use in developing alternative cost
12 allocation factors is also a consideration. In evaluating any cost allocation
13 methodology, appropriate consideration should be given to whether it provides a sound
14 rationale or theoretical basis, whether the results reflect cost causation and are
15 representative of the costs of serving different types of customers, as well as the
16 stability of the results over time.
17

18 **Q. What is the source of the cost data analyzed in MGUC's class COSS?**

19 A. All cost of service data have been extracted from MGUC's revenue requirements and
20 rate base contained in the instant filing as shown in Witness Zgonc's Exhibits A-11
21 through A-14 for the 2022 projected test year. Where more detailed information was
22 required to perform various supplementary analyses related to certain plant and expense
23 elements, the data was taken directly from MGUC's various software systems.
24

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Q. Could you please describe the external allocation factors used in MGUC's class**
2 **COSS?**

3 A. External allocation factors are developed using either historic or test year values that
4 are known prior to performing the cost of service study. External allocation factors
5 include data such as number of customers, total throughput, and other data being
6 provided as part of case filing in workpapers ALN-1, ALN-2, and ALN-3.

7

8 **Q. Have you made any changes to the classes of customers included in the class COSS**
9 **you prepared for the instant general rate case compared to the class COSS**
10 **submitted in MGUC's most recent rate case?**

11 A. No, I have not.

12

13 **Q. What classes of customers are included in MGUC's class COSS?**

14 A. MGUC's class COSS includes the customer classes under which MGUC currently
15 provides retail service in Michigan. A complete list of the customer classes used in
16 MGUC's class COSS includes:

- 17 1. General Service–Residential, including residential heating, general, and
18 lighting,
- 19 2. General Service–Small, including commercial lighting,
- 20 3. General Service–Large,
- 21 4. Transportation–TR-1,
- 22 5. Transportation–TR-2,
- 23 6. Transportation–TR-3,
- 24 7. Customer Choice–Residential,
- 25
- 26
- 27
- 28
- 29
- 30
- 31

DIRECT TESTIMONY AND EXHIBITS OF
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- 1 8. Customer Choice–Small General Service,
2
3 9. Customer Choice–Large General Service,
4
5 10. Aggregated Transportation–Residential,
6
7 11. Aggregated Transportation–Small General Service,
8
9 12. Aggregated Transportation–Large General Service, and
10
11 13. Special Contract, which consists of one customer who is currently served
12 by MGUC under the terms of a special contract. This customer’s rates are
13 fixed by the terms of the contract and not subject to change in a general
14 rate case proceeding. Therefore, the special contract customer is in a
15 separate column solely to segregate its revenues and associated costs.
16

Test Year Natural Gas Cost of Service Study

17
18
19 **Q. How many versions of the class COSS are you sponsoring in this case?**

20 A. I am sponsoring two versions of MGUC’s natural gas class COSS. Schedules F1.1
21 through F1.5 present MGUC’s class COSS with new allocation methods from those
22 used in the 2016 Rate Case. Support for these schedules is provided in workpapers
23 ALN-1 and ALN-2. Schedules F1.6 through F1.7 (“Alternate 1”) present the results of
24 MGUC’s class COSS conforming to the methodologies used by the class COSS in the
25 2016 Rate Case. Support for class COSS Alternate 1 is provided in workpaper ALN-
26 3. The remainder of my testimony will reference the class COSS version containing
27 MGUC’s new allocation methods unless otherwise stated.
28

29 **Q. Has the Company made any changes to the class COSS model that was used in the**
30 **2016 Rate Case?**

DIRECT TESTIMONY AND EXHIBITS OF
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1 A. Yes, the model we use for performing class cost of service studies has changed since
2 MGUC's 2016 Rate Case. The legacy Excel model that was used in MGUC's 2016
3 Rate Case was integrated onto a new software platform, Utilities International Planner
4 ("UIPlanner"). As a result, we are now able to leverage similarities in methodologies,
5 calculations, and reporting across all WEC utilities. The new model is also integrated
6 with Excel for reporting purposes.

7

8 **Q. Is the Company proposing any changes to the class allocation methodologies from**
9 **those used for cost of service in the 2016 Rate Case?**

10 A. Yes, class COSS allocation methodologies are periodically reviewed and updated for
11 reasons discussed previously.

12

13 **Q. Please summarize the primary cost of service class allocation methodology**
14 **changes that you are proposing in this case.**

15 A. The primary cost of service class allocation methodology changes that I am proposing,
16 and that are included in Exhibit A-16, Schedule F1.1 to F1.5, include:

17

18 1. Eliminating the re-classification of distribution O&M FERC accounts to
19 distribution plant accounts;

20

21 2. Using the allocated results of the labor portion of O&M expenses to
22 allocate other labor-related costs.

23

24 3. Allocating house regulator costs to customer classes by a weighted
25 customer allocator, similar to metering costs; and

26

27 4. Using the allocated results of the labor portion of O&M expenses, plant in
28 service, and total O&M expenses to allocate common administrative and
29 general expenses.

30

31

DIRECT TESTIMONY AND EXHIBITS OF
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1 These proposed changes are being made to further align cost allocation with cost
2 causation and to leverage features available in the new class COSS model being used
3 in this case. I will discuss each of these changes in greater detail later in my testimony.

4
5 **Overview of Allocation Methodologies**

6 **Q. How does MGUC allocate production-related costs to customer classes within the**
7 **class COSS?**

8 A. MGUC's production-related costs includes the commodity cost of gas, gas supply
9 acquisition O&M expenses, and related general plant, common administrative and
10 general expenses, depreciation, and taxes. MGUC also has O&M expenses relating to
11 the deferred accounting of costs associated with the remediation of former
12 manufactured gas plant sites, as discussed in Witness Zgonc's direct testimony. Since
13 these production-related costs generally cannot be traced back to individual customers
14 they are classified as either commodity- or demand-related. The commodity
15 classification is further separated into sub-categories of purchased gas cost and gas
16 supply acquisition.

17
18 The commodity cost of gas sold which is recovered via MGUC's Gas Cost Recovery
19 ("GCR") plan are the only production costs classified as purchased gas costs.

20
21 Other commodity-related costs not including the cost of gas sold were assigned to the
22 gas supply acquisition classification and allocated to the sales customer classes based
23 on the throughput of those sales customer classes.

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1 Production demand-related costs include those O&M expenses relating to the
2 remediation of former manufactured gas plant sites in FERC Accounts 710-742. These
3 production demand-related costs are allocated to customer classes based upon each
4 class's maximum monthly volumes, or group peak demand, similar to the 2016 Rate
5 Case.

6
7 **Q. How does MGUC allocate storage-related costs to customer classes within the**
8 **class COSS?**

9 A. MGUC's storage-related costs are those relating to underground storage in FERC
10 Accounts 350-357 and 814-842, and the rate base working capital component gas
11 stored underground in FERC Account 164. These costs are classified as storage
12 demand-related and are allocated to customer classes based upon the storage allocation
13 factor, similar to the 2016 Rate Case.

14
15 **Q. How does MGUC allocate transmission-related costs to customer classes within**
16 **the COSS?**

17 A. Transmission plant is high pressure main typically used for transporting bulk quantities
18 of gas from an interstate pipeline to the utility's distribution system load centers. A
19 majority of the investment that is functionalized to transmission for MGUC is related
20 to transmission main in Plant Account 367. Similar to historical practice, transmission
21 investment in Plant Account 367 and related operation and maintenance expenses in
22 Accounts 856 and 863 were allocated between the customer- and demand-related
23 classification using a regression analysis of the cost and size of transmission main in
24 service at MGUC. The results of the regression analysis from Case No U-17880 are

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1 being used in the current study submitted in this case. Those results create an allocation
2 between the customer- and demand-related classification of 60.4% and 39.6%,
3 respectively. Once classified, the demand-related portion of transmission main was
4 allocated to customer classes based on the group peak demand allocation factor and the
5 remaining costs were allocated to customer classes based on the total throughput
6 allocation factor, similar to the 2016 Rate Case.

7
8 Transmission-related costs other than those specific to transmission main were
9 classified as demand related and allocated to customer classes based on the group peak
10 demand allocation factor, similar to the 2016 Rate Case.

11
12 **Q. How are distribution-related costs classified in MGUC's class COSS?**

13 A. The distribution system is built to meet two criteria. It must connect to all customers
14 and it must be capable of delivering the total gas volumes demanded from each of the
15 customers connected to it during peak demand periods. Therefore, the distribution
16 system should be classified as having both customer- and demand-related components.
17 The costs for connecting customers to the distribution system are related to the number
18 of customers and should be assigned to the customer-related classification. The theory
19 is that there are costs associated with serving all customers even if they only use a
20 minimal amount of energy (or even no energy at all). The remaining costs are
21 considered to be demand-related and should be assigned to the demand-related
22 classification. I will discuss the process of classifying MGUC's distribution-related
23 costs in more detail.

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Q. How are distribution-related costs allocated to customer classes in MGUC's class**
2 **COSS?**

3 A. In general, distribution customer-related costs are allocated to customer classes by the
4 number of customers within each class, and distribution demand-related costs are
5 allocated to classes by the group peak demand of each class. I will discuss a few
6 instances where it is reasonable to incorporate a weighting factor into the allocation of
7 certain distribution customer-related costs, such as service lines (Plant Account 380).
8 A weighting factor is developed based on a detailed study of actual investment or costs
9 by customer class. The weighting factor is used to account for differences in the
10 average costs to serve each customer class.

11

12 **Q. How are miscellaneous distribution plant costs (plant accounts 374 and 375)**
13 **allocated to customer classes?**

14 A. These two plant accounts were classified as 100% demand-related and allocated to
15 customer classes based upon the group peak demand allocation factor.

16

17 **Q. Please describe in more detail how distribution main (Plant Account 376) was**
18 **allocated to customer classes.**

19 A. Distribution main is booked to Plant Account 376 and consists of a network of smaller
20 diameter pipe, typically ranging between 2 and 12 inches at MGUC, responsible for
21 delivering volumes of gas to a number of end-use locations. Similar to historical
22 practice, distribution main investment in Plant Account 376 was allocated between the
23 customer- and demand-related classification using a regression analysis of the cost and
24 size of distribution main in service at MGUC. The results of the regression analysis

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1 from Case No U-17880 are being used in the current study submitted in this case.
2 Those results create an allocation between the customer- and demand-related
3 classification of 54.3% and 45.7%, respectively. Once classified, the customer-related
4 portion of distribution main was allocated to customer classes based on the customer
5 allocation factor and the demand-related portion of distribution main was allocated to
6 customer classes based on the group peak demand allocation factor.
7

8 **Q. How are distribution measuring and regulating station equipment (Plant**
9 **Accounts 378 and 379) allocated to customer classes?**

10 A. Gate stations represent the transfer point between the interstate pipeline and the local
11 distribution company ("LDC"). Typically, these stations have measurement and
12 odorizer equipment. Regulator stations regulate the pressure between two systems by
13 controlling the flow of gas through the distribution system. Similar to historical
14 practice, these two plant accounts were classified as 100% demand-related and
15 allocated to customer classes based upon the group peak demand allocation factor.
16

17 **Q. How are service lines (Plant Account 380) allocated to customer classes?**

18 A. A service line is a lateral installed off distribution or high pressure main in order to
19 serve a customer request for gas. In general, the more gas demanded by a customer or
20 group of customers, the larger and more costly the service lateral will be. Each service
21 line can be traced back to a specific customer, or group of customers in the case of
22 some residential and small commercial accounts. Therefore, service lines were
23 classified as 100% customer-related and allocated to customer classes using a weighted
24 customer allocation factor. Similar to historical practice, the weighted customer

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1 allocator represents an estimate of the service line replacement cost per customer.

2

3 **Q. How are metering related costs (Plant Account 381) allocated to customer classes?**

4 **A.** Meters measure the amount of gas used for billing. General practice is to install one
5 meter per customer. There are three types of meters that can be installed depending on
6 a customer's requirements for gas: 1) diaphragm, for low flow; 2) rotary, for medium
7 flow; and 3) turbine, for high flow. Meter costs (Plant Accounts 381 and 382) can be
8 more directly assigned to customer classes because we know which meters serve which
9 customers. Therefore, we can add up the number of meters serving each class. For this
10 reason, metering costs were classified as 100% customer-related and allocated to
11 customer classes by a weighted customer allocation factor. The weighted customer
12 allocation factor represents an estimate of the current average meter cost per customer.
13 Our metering department supplied estimates of the unit costs for meters. We derived
14 allocation factors for each class by multiplying the number of meters in each class by
15 the estimated unit cost of meters in each class. We then allocated these costs to
16 customer classes proportionally to these allocation factors.

17

18 **Q. Have you changed how house regulators (Plant Account 383) were allocated**
19 **within MGUC's class COSS from what was performed in the class COSS in the**
20 **2016 Rate Case?**

21 **A.** Yes, I have.

22

DIRECT TESTIMONY AND EXHIBITS OF
AARON L. NELSON

1 **Q. Please explain how house regulators were allocated within MGUC's class COSS**
2 **in the 2016 Rate Case.**

3 A. In the 2016 Rate Case, these costs were classified as 100% customer-related and
4 allocated to customer classes based on the pro rata share of the number of customers
5 within each customer class. This resulted in an average regulator cost per customer for
6 the residential class being the same as that for commercial and industrial customers.

7

8 **Q. What changes are you proposing for the allocation of house regulators in this**
9 **case?**

10 A. A meter set is typically accompanied by one or more regulators that can vary in size
11 depending on the size and complexity of the metering configuration. Regulators adjust
12 the delivery pressure and flow rate of natural gas to that which is required at the
13 customers premises. In the cost of service study, and similar to past practice, regulators
14 continue to be classified as 100% customer-related. Larger meter sets require
15 regulators that are more costly in material, design, and installation than regulators for
16 smaller meter sets. For this reason, the class allocation of regulators has been updated
17 to reflect the average cost of regulators per customer class using a weighted customer
18 allocation factor, similar to the methods used for Plant Accounts 380 and 381.
19 Regulators and other accessories that accompany the largest meter installations, which
20 I will discuss shortly, are booked to Plant Account 385, industrial measuring and
21 regulating equipment. For this reason, these large, unique installations have been
22 excluded from the regulators allocation factor.

23

24 **Q. How are distribution industrial measuring and regulating equipment (Plant**

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AARON L. NELSON

1 **Account 385) allocated to customer classes?**

2 A. Industrial measuring and regulating station equipment are large, unique installations of
3 measuring and regulating equipment used by large commercial and industrial
4 customers. This equipment has been defined as meter sets larger than 16,000 cubic feet
5 per hour ("CFH"). The accessories that accompany these large, unique metering
6 installations, such as regulators, piping, fittings, valves, etc. are booked to Plant
7 Account 385. Similar to past practice, this account was allocated to those customer
8 classes having customers with these unique meter installations. Since we know which
9 meters serve which customers, we can identify the number of these large, unique meter
10 sets per customer class. Therefore, industrial measuring and regulating station
11 equipment were classified as 100% customer-related and allocated to customer classes
12 using a weighted customer allocation factor. The weighted customer allocation factor
13 represents an estimate of the current average industrial-sized meter cost per customer.
14 Our metering department supplied estimates of the unit costs for industrial-sized
15 meters. We derived allocation factors for each class by multiplying the number of
16 industrial-sized meters in each class by the estimated unit cost of industrial sized meters
17 in each class. We then allocated these costs to customer classes proportionally to these
18 allocation factors.

19

20

21 **Q. Have you changed how distribution O&M expenses were allocated to customer**
22 **classes within MGUC's class COSS from what was performed in the class COSS**
23 **in the 2016 Rate Case?**

24 A. Yes, I have.

25

DIRECT TESTIMONY AND EXHIBITS OF
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1 **Q. Please explain how distribution O&M expenses were allocated to customer classes**
2 **within MGUC's class COSS in the 2016 Rate Case.**

3 A. In general, these expenses were allocated in the same manner used for the gross plant
4 values of each respective account. In order to achieve this allocation in the COSS
5 model, distribution O&M Accounts 870 through 894 were translated to their equivalent
6 plant distribution Accounts 374 through 386 based on plant investment in either mains
7 and services, metering and regulation, or all distribution plant investment. For
8 example, the balance in Account 874, Mains and Services Expense, was allocated to
9 Accounts 376 and 380 on the basis of distribution plant investment in Plant Accounts
10 376 and 380. Distribution O&M expenses were then input and portrayed in the COSS
11 as Accounts 374 through 386.

12

13 **Q. What changes are you proposing for the allocation of distribution O&M expenses**
14 **to customer classes in this Case?**

15 A. The proposed changes are primarily related to how these expenses are displayed in the
16 class COSS. Our current analysis maintains FERC O&M distribution Accounts 870
17 through 894 throughout the entire class COSS. One change in class allocation was
18 made to Account 871, load dispatching, which I will discuss later.

19

20 **Q. Please explain in more detail how distribution O&M expenses were allocated to**
21 **customer classes in MGUC's class COSS.**

22 A. In general, distribution O&M expenses are classified and allocated to customer classes
23 based upon the allocated results of the gross plant values of each respective account.
24 This includes mains, measuring and regulation equipment, service lines, and meters.

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1 Load dispatching costs (Account 871) is classified as 100% demand-related and is
2 allocated to customer classes based upon group peak demand. This compares to the
3 2016 Rate Case, where Account 871 was allocated to customer classes based upon the
4 allocated results of all other distribution O&M expenses, including customer-related
5 distribution O&M expenses. Customer installations (Account 879) are classified as
6 100% customer-related and allocated to customer classes based upon the allocated
7 results of all other customer-related distribution O&M expenses, similar to the method
8 used in the 2016 Rate Case. Supervision and engineering (Accounts 870 and 885) and
9 other distribution (Accounts 880 and 894) are classified and allocated to customer
10 classes based upon the allocated results of all other distribution O&M expenses, also
11 similar to the method used in the 2016 Rate Case.

12

13 **Q. How are customer costs categorized?**

14 A. FERC USOA defines customer costs as Accounts 901 through 917. We categorize
15 Accounts 901, 902, 903 and 905 as customer accounting costs. Uncollectibles in
16 Account 904 are categorized separately from customer accounting costs for allocation
17 purposes. MGUC doesn't have any forecasted costs in Account 906. Accounts 907
18 through 910 are categorized as customer service costs. Accounts 911 through 917 are
19 categorized as customer sales costs.

20

21 **Q. How does MGUC allocate customer O&M costs to each customer class?**

22 A. Customer accounting costs were allocated to customer classes based on the number of
23 customers within each customer class. Costs that could be directly related and assigned
24 to transportation customers were identified and allocated directly to those customers

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1 based on a specific transportation customer allocation factor. Expenses in Account 904
2 uncollectibles, as well as customer services and sales were allocated to customer classes
3 based on a total margin revenue allocation factor.

4

5 **Q. How did MGUC allocate common administrative and general expenses to**
6 **customer classes?**

7 A. Common administrative and general (“A&G”) expenses are defined as FERC Accounts
8 920 through 935. These expenses were allocated to customer classes based on the
9 allocated results of other cost values within MGUC’s class COSS. The underlying
10 theory is that common A&G expenses are caused by, or follow in proportion to, other
11 utility expenses and plant investments.

12

13 **Q. Have you changed the allocation of A&G expenses to customer classes as**
14 **compared to what was done in the 2016 Rate Case?**

15 A. Yes, I have.

16

17 **Q. Please explain how A&G expenses were allocated in the 2016 Rate Case.**

18 A. Historically, A&G expenses were functionalized to production, storage, transmission,
19 distribution, and customer functions based upon a salaries and wages external
20 allocation factor. The production function was further sub-categorized between gas
21 supply acquisition and production demand based upon the percentage of production
22 O&M costs to total O&M costs in the projected test year. The distribution function
23 was further sub-categorized between distribution demand and distribution customer
24 based upon the percentage of distribution O&M costs to total O&M costs in the

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1 projected test year. The transmission function was further sub-categorized between
2 distribution demand and distribution customer based upon the percentage of
3 transmission O&M costs to total O&M costs in the projected test year.

4
5 Gas supply acquisition and production demand-related A&G expenses were allocated
6 to the customer classes based upon the sales and group peak demand allocation factors,
7 respectively. Storage related A&G expenses were allocated to customer classes based
8 upon the storage allocation factor. Distribution demand-related A&G expenses were
9 allocated to customer classes based upon the allocated results of distribution demand
10 related O&M expenses. Customer related A&G expenses were allocated to customer
11 classes based upon the allocated results of customer-related O&M expenses.

12
13 **Q. What changes are you proposing for the allocation of A&G expenses to customer**
14 **classes in this case?**

15 A. There are two changes being proposed to the allocation of A&G expenses in this case.
16 First, each FERC Account was assigned to one of the following three categories (1)
17 labor-related, consisting of Accounts 920, 925, and 926; (2) plant-related, consisting of
18 Accounts 924 and 932; and (3) general O&M, consisting of Accounts 921–923 and
19 927–931. Once these accounts were assigned to these categories, each category used
20 the allocated results from costs within the COSS to functionalize, classify, and allocate
21 each A&G expense category to customer classes. This compares to using both external
22 and internal allocation factors which was the method used in the 2016 Rate Case.

23
24 **Q. Please discuss in more detail how A&G expenses are allocated to customer classes.**

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1 A. The labor-related category of A&G expenses was functionalized, classified, and
2 allocated to customer classes based upon the allocated results of the labor portion of
3 O&M expenses, excluding other A&G expenses. The plant-related category of A&G
4 expenses was functionalized, classified, and allocated to customer classes based upon
5 the allocated results of plant in service. The general O&M-related category of A&G
6 expenses was functionalized, classified, and allocated to customer classes based upon
7 the allocated results of all other total O&M expenses, excluding other A&G expenses.

8

9 **Q. How did MGUC allocate general and intangible plant to customer classes?**

10 A. General and intangible plant consists of assets used to support MGUC's utility services
11 but not readily categorized to a specific utility function. We would not be able to
12 provide these services without the general plant assets. Communication devices,
13 computer equipment, and vehicles supporting MGUC's utility functions are all
14 examples of general plant. Similar to the 2016 Rate Case, general and intangible plant
15 was allocated to customer classes based upon the allocated results of other gross plant
16 in service. Plant costs related to the implementation of the Integrated Customer
17 Experience ("ICE") systems were directly assigned to the customer-related
18 classification.

19

20 **Q. Please describe how income taxes are allocated to customer classes.**

21 A. Similar to the 2016 Rate Case, current and deferred income taxes were allocated to
22 customer classes based upon the allocated results of rate base.

23

24 **Q. How are accumulated deferred income taxes allocated to customer classes?**

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1 A. Our tax department functionalizes these items as production, storage, transmission,
2 distribution, or general costs. Each of the functionalized components were allocated to
3 customer classes based upon the allocated results of their respective gross plant value.
4

5 **Q. Please describe the remaining components of the MGUC class COSS.**

6 A. The remaining components of the cost of service include:

- 7
- 8 1. Taxes other than income relating to unemployment compensation, payroll,
9 and retirement benefits were allocated to customer classes based upon the
10 allocated results of the labor portion of O&M expenses, not including A&G
11 expenses.
12
 - 13 2. Rate base component cash working capital was allocated to customer classes
14 based upon the allocated results of rate base.
15
 - 16 3. Miscellaneous Revenues in Account 487 attributable to late payments were
17 allocated to customer classes based on the margin revenue allocation factor.
18 Amounts booked to this account are based upon a percentage of customers'
19 total bill balances.
20
 - 21 4. Rate base component materials and supplies in Account 154 was allocated to
22 customer classes based on the allocated results of distribution plant in service.
23
 - 24 5. The 2021 revenue requirement deferral resulting from capital investments
25 made by MGUC between Jan. 1, 2016, and Dec. 31, 2019 was allocated to
26 customer classes based upon the allocated results of rate base.
27

28
29
30 **Natural Gas Class COSS for the 2022 Projected Test Year**

31 **Q. Please describe Exhibit A-16, Schedule F1.1.**

33 A. Schedule F1.1 summarizes the development of the allocated rate base, operating
34 income, and revenue deficiency values by rate class at present rates for MGUC's 2022
35 projected test year. The rate classes presented on this schedule are categorized into 1)
36 general service residential, 2) general service small commercial, 3) general service

DIRECT TESTIMONY AND EXHIBITS OF
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1 large commercial, 4) transport, including customer choice and aggregated transport,
2 and 5) special contract.

3

4 **Q. Please describe Exhibit A-16, Schedule F1.2.**

5 A. Schedule F1.2 summarizes the development of the allocated rate base, operating
6 income, and revenue deficiency values by customer class at present rates for MGUC's
7 2022 projected test year. Schedule F1.2 presents the same information as Schedule
8 F1.1 just at a more disaggregated customer class level using the classes of customers
9 described earlier in this testimony.

10

11 **Q. Please describe Exhibit A-16, Schedule F1.3.**

12 A. Schedule F1.3 summarizes the unbundled revenue requirements by customer class
13 resulting from MGUC's 2022 projected test year class COSS. Each of the class revenue
14 requirements are summarized by function and classification.

15

16 **Q. Please describe Exhibit A-16, Schedule F1.4.**

17 A. Schedule F1.4 summarizes the unbundled rate base amounts by customer class
18 resulting from MGUC's 2022 projected test year class COSS. Each of the class rate
19 base amounts are summarized by function and classification.

20

21 **Q. Please describe Exhibit A-16, Schedule F1.5.**

22 A. Schedule F1.5 summarizes the unbundled unit costs by customer class as determined
23 by the class COSS for MGUC's 2022 projected test year. A unit cost by function and
24 classification was derived by dividing the unbundled revenue requirement data from

DIRECT TESTIMONY AND EXHIBITS OF
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1 Exhibit A-16, Schedule F1.4 by the related class determinant values (e.g., throughput,
2 number of customers, etc.).
3

4 **Q. Please describe Exhibit A-16, Schedule F1.6.**

5 A. Schedule F1.6 summarizes the development of the allocated rate base, operating
6 income, and revenue deficiency values by rate class at present rates for MGUC's 2022
7 projected test year using class COSS Alternate 1. The rate classes presented on this
8 schedule are categorized into 1) general service residential, 2) general service small
9 commercial, 3) general service large commercial, 4) transport, including customer
10 choice and aggregated transport, and 5) special contract.
11

12 **Q. Please describe Exhibit A-16, Schedule F1.7.**

13 A. Schedule F1.7 summarizes the development of the allocated rate base, operating
14 income, and revenue deficiency values by customer class at present rates for MGUC's
15 2022 projected test year using class COSS Alternate 1. Schedule F1.7 presents the
16 same information as Schedule F1.6 just at a more disaggregated customer class level
17 using the classes of customers described earlier in this testimony.
18

19 **Q. In your opinion, does the MGUC class COSS provide a reasonable basis for**
20 **establishing rates in this case?**

21 A. Yes, it does. The class COSS for MGUC is a reasonable estimate of revenue
22 requirements by customer class, given the total revenue requirement, and supports the
23 rates requested in this case, as explained further in the pre-filed direct testimony of
24 Witness Burzycki.

DIRECT TESTIMONY AND EXHIBITS OF
AARON L. NELSON

1 **Q.** **Does this conclude your direct testimony at this time?**

2 **A.** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

DIRECT TESTIMONY OF

NATHAN W. LEE

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY OF
NATHAN W. LEE

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)
_____)

Case No. U-20718

QUALIFICATIONS
OF
NATHAN W. LEE
PART I

1 **Q. Please state your name, position and business address.**

2 A. My name is Nathan Lee. My business address is 70 Sauk River Drive, Coldwater,
3 Michigan, 49036. I am employed by WEC Business Services, LLC, a subsidiary of
4 WEC Energy Group, Inc. ("WEC"), as Engineering Manager.

5

6 **Q. For whom are you providing testimony?**

7 A. I am providing testimony on behalf of Michigan Gas Utilities Corporation ("MGUC"
8 or the "Company").

9

10 **Q. Please describe briefly your educational, professional, and utility background**

11 A. I received a Bachelor's degree in Math and Physics from the Spring Arbor University and
12 a Bachelor's Degree in Civil Engineering from the University of Michigan. I was hired
13 by MGUC (a subsidiary of WEC) in 2005 and worked in various roles in several
14 departments prior to my current position. I became the Engineering Manager supporting
15 MGUC in December 2019. I received my Professional Engineers License in 2008.

DIRECT TESTIMONY OF
NATHAN W. LEE

NATHAN W. LEE
DIRECT TESTIMONY
PART II

1 **Q. What is the purpose of your pre-filed direct testimony?**

2 A. The purpose of my pre-filed direct testimony is to provide an explanation of and
3 support for the need and customer benefits realized of the significant capital
4 investments that have been placed in service since MGUC's last rate case, which was
5 filed with a 2016 test year, or are forecast to be placed in service during the 2022 test
6 year.

7

8 I will provide an overview of the projects for which MGUC proposed to implement a
9 Main Replacement Program surcharge. These projects are projected to go in service for
10 the years 2023 through 2027, which are all after the current test year.

11

12 **Q. Are you sponsoring any exhibits in this proceeding?**

13 A. No, I am not.

14

15 **OVERVIEW OF SIGNIFICANT CAPITAL INVESTMENT SINCE LAST RATE**
16 **CASE**

17 **Q. What is MGUC's capital spending plan in this rate case?**

18 A. MGUC's 2022 revenue deficiency is mainly driven by its capital spending plan.
19 Between 2016 and 2020, MGUC has placed \$[133.4] million of capital in service.
20 MGUC continued regular distribution system efforts between [2016] and [2018]. In
21 2019, the Company's investment in the utility system more than doubled over the prior

DIRECT TESTIMONY OF
NATHAN W. LEE

1 years, with one-time large projects Coldwater to Quincy and Maple station being
2 placed in service. Meter and replacement services also increased in 2019 from the prior
3 years. Growth projects continued at a steady pace for the same four year period.
4 Beginning in 2017, there has been an increased focus and spend on integrity
5 transmission projects. In 2019, multiple large projects including the Morenci station,
6 Marshall station and Plumb Creek casing replacement were placed in service. In 2016
7 and 2017, MGUC implemented a new customer information system and in 2018 built
8 a new service center in Allegan. As of 2018, in order to standardize processes, MGUC
9 was migrated onto SAP, WEC's enterprise resource planning system.

10 The 2020 capital spend by MGUC was largely driven by the implementation of
11 automated metering infrastructure (AMI) of \$35.1 million. The Company plans to
12 increase the distribution systems integrity and system growth project spend, as well as
13 continuing the increase in transmission integrity work. Combined, the distribution and
14 transmission work amounted to \$27.0 million of MGUC's 2020 spend. Additionally,
15 MGUC continued to invest in the Partello Gas Storage field and its structures. In total,
16 MGUC's 2020 capital spend was \$70.2 million.

17 Forecasted 2021 spend on MGUC distribution system amounts to \$10.5 million, which
18 includes system integrity, replacement of mains and services, road projects, line hits,
19 and stations work and meters. MGUC plans to spend \$8.8 million related to system
20 growth projects and \$4.0 million on its transmission main and stations, which also
21 including continued integrity projects. MGUC is forecasting \$4.0 million to be spent
22 on the Partello Gas Storage field, with \$2.0 million of that related to a compressor
23 replacement. An additional \$5.2 million is projected to be spent in 2021 in relation to

DIRECT TESTIMONY OF
NATHAN W. LEE

1 automated metering infrastructure. In total, MGUC's forecasted capital spend is
2 \$35.4 million in 2021.

3

4 In the section immediately below, I will provide greater detail of the significant capital
5 projects that have been placed in service through the end of 2020 or will be placed in
6 service during 2021 or the 2022 test year.

7 **Automated Metering Infrastructure (AMI)**

8 **Q. Please describe the Automated Metering Infrastructure ("AMI") project included**
9 **in this rate proceeding.**

10 A. The objective of this project is to replace MGUC's existing manual meter reading
11 system with an AMI for all billing meters to remotely read these meters. The overall
12 scope of the project includes 3 primary components: network hardware deployment,
13 module deployment on approximately 176,000 meters, and system implementation to
14 collect, house and deliver meter reads from the AMI system to our MGUC's CIS.

15

16 **Q. How many existing meters will MGUC replace as part of its AMI project ?**

17 A. MGUC will replace approximately 11,000 meters for the initial project.

18

19 **Q. What is the approximate timeline of the planned AMI implementation?**

20 A. Mass deployment is scheduled to conclude at the end of 2021.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Q. Please describe the Company’s evaluation process regarding its AMI solution and**
2 **the vendor identification, evaluation, and selection process.**

3 A. MGUC conducted a market review of proven vendors within the automated meter
4 reading solution space. MGUC then issued a Request for Information (RFI) to vendors
5 to assess the overall viability of each vendor, their solution and pricing review. A
6 Request for Proposal (RFP) was then issued to a qualified short list of vendors to
7 thoroughly analyze each vendor’s solution, which included a review of:

8 - Solution viability

9 - Vendor risk profile

10 - Solution costs

11 - Ongoing operational needs

12 The above criteria was thoroughly vetted by MGUC project stakeholders and executive
13 leadership and the decision was made to proceed with implementing the Itron AMI
14 solution.

15

16 **Q. Describe the benefits that MGUC expects its customers to experience as a result**
17 **of implementing the AMI solution.**

18 A. MGUC expects that the AMI solution will result in improved customer satisfaction by
19 having daily meter reads resulting in more efficient processes (for example faster
20 completion of move-in and move-out requests), fewer estimated bills and building the
21 foundation for providing view of daily consumption.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Q. Has MGUC proposed a tariff that would allow customers to “opt out” of the AMI**
2 **program?**

3 A. MGUC is not proposing an “opt out” program.

4

5 **Q. Why did MGUC decide on AMI rather than Automated Meter Reading (AMR)?**

6 A. MGUC performed due diligence to determine the best solution which included a
7 number of factors including but not limited to customer benefits, total cost of
8 ownership, and ongoing utility operations inclusive of an AMR (drive-by) and AMI
9 solutions. The analysis resulted in MGUC selecting an AMI solution in order to
10 achieve the following key benefits:

- 11 • Reduction in truck rolls resulting in improved safety and reduction in costs;
- 12 • Long-term investment in latest generation of automated meter reading
- 13 technology;
- 14 • Improved customer satisfaction by having daily meter reads resulting in more
- 15 efficient processes (for example faster completion of move-in and move-out
- 16 requests), fewer estimated bills and building a foundation for providing
- 17 customers with a view of daily consumption;
- 18 • Improved system reliability with sensors and remote monitoring; and,
- 19 • Enhanced meter tampering / theft detection capabilities.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **SAP Enterprise Resource Planning (“ERP”)**

2 **Q. Please describe MGUC’s SAP / ERP deployment project.**

3 A. WEC undertook a company-wide project to deploy a single recordkeeping system to
4 replace legacy systems that varied across the various utilities and, in some cases, were
5 nearing or were at the end of their useful lives. This project enhanced integration
6 among the various utilities, reduced the cost associated with supporting and
7 maintaining multiple systems, and allowed standardization of processes and technology
8 across the companies for the Benefits / Payroll / Time Entry, Finance,
9 Procurement / Inventory, and Technical / Reporting functions. MGUC’s deployment
10 began in 2018. The project was undertaken in two phases and was completed in 2020.

11

12 **Q. What alternatives were considered to avoid deploying SAP / ERP?**

13 A. Without the SAP / ERP deployment, MGUC and its sister companies would have had
14 to maintain separate recordkeeping systems, resulting in redundancies and higher
15 maintenance costs for a system that would eventually become obsolete and be more
16 expensive for customers.

17

18 **Q. Was the implementation of this project more complex than originally thought?**

19 A. Yes. The implementation of single, company-wide systems for the Finance,
20 Procurement / Inventory and Technical / Reporting functions was finished as expected
21 in 2018. Unforeseen complexities were encountered with conversion of the
22 Benefits / Payroll / Time Entry system, particularly for the legacy Integrys utilities.

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1 The existing Benefits / Payroll / Time Entry system in use at the legacy Integrys utilities
2 was found to be heavily decentralized and customized, requiring much more work to
3 convert to the new system. WEC therefore decided to implement the new
4 Benefits / Payroll / Time Entry system for the legacy Integrys utilities as a second
5 phase during 2018-2020.

6

7 **Q. What was the cost of this program?**

8 A. The MGUC portion of the SAP / ERP project was \$3.3 million.

9

10 **Q. Was the investment in SAP / ERP prudently undertaken, reasonable in cost, and**
11 **is it used and useful in providing utility service?**

12 A. Yes. Having a standard system for the Benefits / Payroll / Time Entry, Finance,
13 Procurement / Inventory, and Technical / Reporting functions allows the individual
14 utilities, including MGUC, to offer improved customer service, realize efficiencies and
15 reduce costs, while enhancing capabilities.

16

17 **Otsego Service Center Replacement**

18 **Q. Please describe the Otsego Service Center Replacement (“Allegan”) project.**

19 A. This project consisted of replacing the Otsego Service Center with a service center in
20 Allegan. Initial targeted property in Otsego for a replacement service center was not
21 suitable for construction. The Allegan Service Center is approximately 12 miles from
22 the former Otsego Service Center.

DIRECT TESTIMONY OF
NATHAN W. LEE

1

2 **Q. Please discuss the estimated cost of the Otsego Service Center Replacement**
3 **(“Allegan”) project.**

4 A. The total actual cost of this project was approximately \$4.1 million.

5

6 **Q. Is this project currently in service?**

7 A. Yes, this project was placed in service as of December of 2018.

8

9 **Q. Please describe how this project benefits MGUC’s customers.**

10 A. The primary benefits to MGUC’s customers are reduced operating and maintenance
11 expenses as well as addressing existing safety concerns. The former Otsego Service
12 Center had reached its service life, and the deferred maintenance on the building was
13 greater than 50% of the replacement value of the facility. Significant improvements
14 would have been required to the building structure, exterior, mechanical, plumbing and
15 electrical systems to extend the life of the facility, which did not meet space needs of
16 the operations staff. In addition, the location of the facility along the major thoroughfare
17 of the community caused safety issues as company vehicles were entering and exiting
18 the site.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Partello Office and Garage Replacement**

2 **Q. Please describe the Partello Office and Garage Replacement project.**

3 A. The existing office at Partello was built between 1975 and 1980 with a 20 to 30-year
4 useful life. The building was in need of major repairs such as a roof, sanitary drains
5 under the concrete floor, relocation of the SCADA, and internet servers, including
6 electrical wiring, that were housed near the potable water system. The new office
7 building is built and designed to a 40-year standard with a dedicated server room and a
8 security system, and the new office building is compliant with all building codes in
9 place at the time of construction and American Disabilities Act regulations. The garage
10 was a compressor station built in 1975 and later converted to a storage unit. The unit
11 was not designed for storage, which made storing parts and supplies inconvenient, labor
12 intensive and physically-challenging because these items needed to be lifted by hand
13 to floor level which was 4 feet above grade.

14

15 **Q. Please discuss the cost of the Partello Office and Garage Replacement project.**

16 A. The actual cost for this project was \$2 million.

17

18 **Q. Is this project currently in service?**

19 A. Yes, this project was placed in service in 2020.

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1 **Q. Please describe how this project benefits MGUC's customers.**

2 A. The benefits to customers for the Partello Office and Garage replacement is that the
3 SCADA and network servers are located in a designated, safe, secure area to maintain
4 reliable service. The new garage can now store pre-tested/emergency pipe to protect
5 the coating from UV rays and corrosion while allowing easier access to parts and
6 supplies with appropriate machinery to help MGUC quickly respond to a pipeline strike
7 or emergency to minimize customer impact. The accessibility of the new garage also
8 reduces the risk of potential employee injuries.

9 **Partello Compressor Unit Replacement**

10 **Q. Please describe the Partello Compressor Unit Replacement project.**

11 A. The Partello Compressor Unit Replacement project will replace Unit 5, one of the two
12 compressor units. Unit 5 was installed in 1980 and has a MAOP of 900 psig. Two of
13 the three reservoirs at Partello have a 1300 psig MAOP. Unit 5 is only operated to
14 compress gas below 900 psig. Unit 5 will be a twin to Unit 6 which was installed in
15 2005 and has updated fuel and emissions controls. This will create full redundancy,
16 increase reliability throughout the entire injection cycle and give the facility the
17 capability to operate at full pressure of 1300 psig. This will also standardize parts and
18 maintenance procedures, reduce operations and maintenance repairs, and provide better
19 accessibility to parts.

20 **Q. Please discuss the estimated cost of the Partello Compressor Unit Replacement**
21 **project.**

22 A. The estimated cost for this project is \$2 million.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Q. Is this project currently in service?**

2 A. No, this project is estimated to be placed in service in 2022.

3

4 **Q. Please describe how this project benefits MGUC's customers.**

5 A. Building off of the response above, the Partello Compressor project will benefit
6 customers by increasing reliability, providing redundancy, and reducing operations and
7 maintenance expenses.

8 **Partello Wells**

9 **Q. Please describe the Partello Wells Planning project.**

10 A. The Partello Wells Planning project will upgrade and make improvements to wells and
11 the reservoir to comply with the Storage Integrity Management Program ("SIMP") and
12 Standard API 1171. This includes the removal of sub-surface safety valves and
13 replacement with new surface safety valves, improvements to wellhead equipment and
14 telemetry, and establishment of a corrosion logging program for the wells. These
15 improvements will minimize risk when performing well work and logging operations
16 and eliminate the need for well kill and wireline equipment for maintenance, which
17 carries a high level of risk.

18

19 **Q. Please discuss the estimated cost of the Partello Wells Planning project.**

20 A. The estimated cost for this project is \$1.2 million.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Q. Is this project currently in service?**

2 A. No, this project is estimated to be placed in service in 2022.

3

4 **Q. Please describe how this project benefits MGUC's customers.**

5 A. The gas storage at Partello allows MGUC to purchase gas in the summer when prices
6 are low, place it in storage, and then withdraw gas in the winter when gas purchases off
7 of the pipelines are more expensive. These cost savings benefit MGUC customers
8 directly through lower Gas Cost Recovery ("GCR") charges. The Partello Wells
9 Planning project allows MGUC to maintain the wells and reservoir for reliability and
10 ensures operational longevity of the storage field. The project also improves safety and
11 reduces operations and maintenance expenses.

12

13 **Capital Projects Undertaken to Reduce Gas Costs and Improve System**

14 **Reliability and Redundancy for MGUC's Customers**

15 **Q. Are there any projects you would like to discuss that will reduce gas costs and**
16 **improve the reliability and redundancy of distribution assets?**

17 A. Yes. A variety of projects were completed from 2017-2020 that align with MGUC's
18 Transmission Integrity Management Program ("TIMP") and Distribution Integrity
19 Management Program ("DIMP"). These programs are designed to reduce pipeline
20 risks and increase customer reliability. Under TIMP this includes gate station rebuilds
21 to update telemetry, regulation, heaters, odorization, filters, station protection and to
22 increase system capacity. This also included replacing higher risk transmission lines
23 in High Consequence Areas. Under DIMP this includes Bare Steel Main Replacement,

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1 which all legacy bare main steel has been replaced in the MGUC system as of 2020,
2 regulator structure replacements, replacing main with shorted casings, replacing
3 exposed mains, eliminating Master Meter Systems and extending main and adding
4 valves to systems to increase reliability and safety.

5

6 I will describe these projects, their capital costs, actual or forecasted in-service dates,
7 and expected customer benefits in more detail below.

8

9 **Q. Please describe the Marshall Station Vector Interconnect project?**

10 A. This project consists of installing a new interconnect on MGUC's 8" line from
11 Partello Storage to Division Drive. The project also included a new station and the
12 replacement of approximately 1,215 feet of 8" steel main to relocate existing pipeline
13 into the footprint of the station.

14

15 **Q. Please discuss the actual cost of the Marshall Station Vector Interconnect.**

16 A. The Marshall Station project actual cost was \$4.1 million.

17

18 **Q. Is this project currently in service?**

19 A. Yes, this project was placed in service in 2019.

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1 **Q. Please describe how this project benefits MGUC's customers.**

2 A. MGUC's customers benefit by the addition of a new gas supplier to MGUC's overall
3 supply portfolio at a lower supply cost. In addition, this project allows for future
4 distribution customer capacity or transportation account capacity.

5

6 **Q. Please describe the Plumb Creek casing replacement project.**

7 A. This project consists of the replacement of 1,000 feet of 1960 vintage cased steel main.
8 The main is shorted to the casing, which eventually causes the loss of cathodic
9 protection.

10

11 **Q. Please discuss the cost of the Plumb Creek casing replacement project.**

12 A. The actual cost of this project was \$1.4 million.

13

14 **Q. Is this project currently in service?**

15 A. Yes, this project was placed in service in 2019.

16

17 **Q. Please describe how this project benefits MGUC's customers.**

18 A. The project benefits MGUC customers by reducing the risk of pipe leaks and failure of
19 steel main that was approaching 60 years in age, which now that completed has
20 improved customer reliability.

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NATHAN W. LEE

1 **Q. Please discuss the cost of the Morenci Metering Station project.**

2 A. This project consists of replacement of existing meters, strainers, shelter, and control
3 equipment at the Morenci station.

4

5 **Q. Please discuss the cost of the Morenci Metering Station project.**

6 A. The actual cost of this project was \$1.0 million.

7

8 **Q. Is this project currently in service?**

9 A. Yes, this project was placed in service in 2019.

10

11 **Q. Please describe how this project benefits MGUC's customers.**

12 A. The benefit to MGUC customers includes the ability to supply the Monroe District with
13 additional ANR capacity, with a reduced reservation charge compared to Panhandle
14 Eastern Pipeline (PEPL) and increased reliability with a redundant source of supply.

15

16 **Q. Please describe the Coldwater to Quincy project.**

17 A. This project consists of installing approximately 7.5 miles of 8" high pressure steel
18 main from Coldwater to Quincy, adding, a new station at Maple Road (east of Quincy),
19 and installing a high pressure tap at the Fiske Station to place the new pipeline in
20 service, as well as installing valves for future pigging operations.

DIRECT TESTIMONY OF
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1

2 **Q. Please discuss the cost of the Coldwater to Quincy project.**

3 A. The actual cost for this project was \$6.3 million

4

5 **Q. Is this project currently in service?**

6 A. Yes, this project was placed in service in 2019.

7

8 **Q. Please describe how this project benefits MGUC's customers.**

9 A. The benefits of this project to MGUC customers is increased reliability in the area
10 served, reduction of risk of high pressure failure and customer interruption, and
11 increase capacity for continued customer growth in the area. Prior to the
12 implementation of this project, the facilities did not allow for any additional load east
13 of the Fiske Station. In addition, the opportunity to bring natural gas service to new
14 towns in this area had been limited by system capacities.

15

16 **Q. Please describe the Marshall HCA Relocate project.**

17 A. This project consists of replacing an existing 8" steel transmission main that runs
18 parallel to Oliver street on the south side of Marshall. This line runs through two High

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NATHAN W. LEE

1 Consequence Areas¹. The new line includes a 12” steel line that was re-routed through
2 a rural area and no longer classified as transmission main.

3

4 **Q. Please discuss the actual cost of the Marshall HCA Relocate.**

5 A. The actual cost for this project was \$1.9 million.

6

7 **Q. Is this project currently in service?**

8 A. Yes, this project was placed in service in 2020.

9

10 **Q. Please describe how this project benefits MGUC’s customers.**

11 A. The primary benefits to MGUC’s customers is a reduction of safety concerns in a
12 highly-congested industrial area, reducing the risk of 3rd party damages, and rupture as
13 the new line will operate at a significantly lower pressure.

14

15 **Q. Please describe the Partello Transmission Pipeline Replacement Project.**

16 A. This project consists of replacing approximately 15 miles of existing 8” steel
17 transmission main installed in 1960 with 10” steel line. The replacement PTP begins at
18 the Partello Compressor facility in the northeast ¼ of Section 13, Town 1 South, Range

¹ High Consequence Area is defined in 49 CFR Part 192.903 and is generally defined as a location that is specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment.

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1 5 West, Lee Township, Calhoun County and extending in a southwestern direction to
2 a point of interconnection at the Marshall Station in the northeast ¼ of Section 1, Town
3 3 South, Range 6 West, City of Marshall, Calhoun County, Michigan. The construction
4 of the PTP is critical to continue to provide safe, reliable, cost efficient natural gas to
5 MGUC customers while complying with the Transmission Integrity Management
6 Program (“TIMP”).

7

8 **Q. Please discuss the estimated cost of the Partello Transmission Pipeline**
9 **Replacement Project.**

10 A. The total estimated cost of this project is approximately \$19.6 million.

11

12 **Q. Is this project currently in service?**

13 A. No, this project is expected to be in service in October of 2022.

14

15 **Q. Please describe how this project benefits MGUC’s customers.**

16 A. The primary benefits that will be realized by MGUC’s customers include reduced
17 safety concerns by operating at a lower percent Specified Minimum Field Strength
18 (“SMYS”), reduced risk of rupture, and increased reliability and capacity from the
19 storage field to the distribution system.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **OVERVIEW OF PROJECTS IN SCOPE OF PROPOSED MRP SURCHARGE**

2 **Q. Are there any other aspects of the Company’s case that you would like to provide**
3 **any comment?**

4 A. Yes. I will also provide an overview of 5 projects that would be funded by the MRP
5 rider charge that is being proposed by Company Witness Burzycki.

6

7 **Q. How many projects would be funded by the MRP charge, if approved by the**
8 **Commission?**

9 A. There are a total of six projects that would be included in the scope of the MRP charge.
10 The projects are included in the table below.

Project Name	Estimated Capital Costs	In Service Year(s)
Allegan Transmission Relocation	\$ 2,200,000	2023
Creque Road Station	\$ 800,000	2023
Coldwater-Marshall Pipeline	\$ 26,675,000	2024 – 2026
M-89 Otsego	\$ 500,000	2027
Grand Haven	\$ 900,000	2027
Otsego Paper Service Line	\$ 625,000	2027

11 **Q. Can you provide a brief description of each of these projects and a brief**
12 **description of the benefits for each, please?**

13 A. Certainly. The Allegan Transmission Relocation project will involve relocating 2 miles
14 of 8" transmission line. The impact of this project will be lowering operating percent
15 Specified Minimum Yield Strength (“SMYS”), relocate to a less inhabited area, as well
16 as eliminate High Consequence, Moderate Consequence, and Class 3 locations.

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1 Creque Road Station project will install Station to lower downstream pressure on 2.25
2 miles of 12” transmission main to a lower operating percent SMYS, eliminate High
3 Consequence, Moderate Consequence, and Class 3 locations, and decrease operational
4 risk.

5 The Coldwater-Marshall Pipeline project will replace 19.5 miles of 10" transmission
6 installed in 1952 with 12" pipe. This allow MGUC to operate that pipeline at lower
7 operating percent SMYS, increase system capacity, and eliminate Moderate
8 Consequence and Class 3 areas

9 The M-89 Otsego Project will involve relocating 1/4 mile of 8" transmission line to
10 lower operating percent SMYS, and eliminate a Class 3 location.

11 The Grand Haven Project will relocate 1/2 mile of 8" transmission line to lower
12 operating percent SMYS and eliminate a Moderate Consequence location and a Class
13 3 location.

14 The Otsego Paper Service Line Project will relocate 1/4 mile of 8" transmission line to
15 lower operating percent SMYS, which will eliminate a Class 3 location.

16 In addition to the specific benefits noted above for each project, completing those
17 projects will also eliminate assessments, material verification, and MAOP
18 reconfirmation that are required by the 2019 “Mega” Rule (84 FR 52180), which is
19 further explained later in my testimony.

DIRECT TESTIMONY OF
NATHAN W. LEE

1 **Q. In the benefits of the projects noted above you noted a benefit related to lower**
2 **operating percent SMYS. Can you explain what you mean by that and how that**
3 **is a benefit to MGUC’s customers?**

4 A. ”SMYS” stands for Specified Minimum Yield Strength and it refers to the strength of
5 the steel used to make the pipe. In general, the higher percentage of SMYS a pipeline
6 operates at the higher the risk is. In addition, pipelines operating above 20% of SMYS
7 are considered “transmission pipelines” and have an increased risk of rupturing instead
8 of leaking. Operating a lower risk pipeline is safer for MGU customers.

9

10 **Q. Similarly, you identified eliminating High Consequence Areas (HCA), Moderate**
11 **Consequence Areas (MCA), and / or Class 3 locations as a benefit of many projects**
12 **noted above. Can you explain what you mean by those terms and how eliminating**
13 **those locations is a benefit to MGUC’s customers?**

14 A. The 2019 “Mega” Rule (84 FR 52180) issued by the Pipeline and Hazardous Materials
15 Safety Administration (PHMSA) requires that integrity assessments, material
16 verification, and MAOP (maximum allowable operating pressure) reconfirmation be
17 performed on pipelines in areas that meet the definitions of High Consequence Areas,
18 Medium Consequence Areas, and Class 3 locations, as defined in 49 CFR Part 192.
19 Each of those terms are only applicable to transmission mains and are therefore of
20 higher risk (higher probability of failure) due operating at a higher percentage of SMYS
21 (>20%). In addition, each of these terms applies to areas with a higher concentration
22 of people, which further increases the risk (higher consequence of failure). When we
23 replace these pipeline segments, we install higher grade and thicker steel which lowers

DIRECT TESTIMONY OF
NATHAN W. LEE

1 the probability of failure and often relocate away from large concentrations of people
2 which lowers the consequence of failure. Lastly, additional periodic surveys and
3 assessments are required on certain mains located in HCAs, MCAs, or Class 3
4 locations. These assessments are costly and often require excavation, large equipment,
5 traffic lane closures, and other items that are a general nuisance to the public.

6

7 **Q. Does that complete your testimony?**

8 **A. Yes, it does.**

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
MICHIGAN GAS UTILITIES CORPORATION	)	
for authority to increase retail natural gas rates	)	Case No. U-20718
and for other relief.	)	
_____	)	

DIRECT TESTIMONY AND EXHIBITS OF

SHANNON L. BURZYCKI

FOR

MICHIGAN GAS UTILITIES CORPORATION

March 22, 2021

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

**QUALIFICATIONS
OF
SHANNON L. BURZYCKI
PART I**

1 **Q. Please state your name, business address and position.**

2 A. My name is Shannon L. Burzycki. My business address is 899 S. Telegraph, Monroe,
3 Michigan 48161. I am a State Regulatory Affairs Project Specialist for Michigan Gas
4 Utilities Corporation (“MGUC” or the “Company”). MGUC is a wholly-owned
5 subsidiary of WEC Energy Group Inc. (“WEC”).

6
7 **Q. On whose behalf are you providing testimony?**

8 A. I am providing testimony on behalf of MGUC.

9
10 **Q. Briefly describe your educational, professional, utility background and current**
11 **job responsibilities.**

12 A. I graduated from Eastern Michigan University in 1997 with a Bachelor of Business
13 Administration, majoring in Accounting.

14
15 In June of 2006, I was hired by Wisconsin Public Service Corporation (“WPS”) as a
16 Senior Accountant for MGUC. In 2011, I became an employee of WBS Business
17 Support (a subsidiary of WEC) after the acquisition of WPS by WEC, continuing to
18 provide accounting services and support exclusively to MGUC. At the start of my
19 career with MGUC, I calculated the cost of gas and provided support for the annual
20 Gas Cost Reciver (“GCR”) Reconciliation Audit. My duties have included General

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 Ledger accounting, providing data and analyses supporting the GCR Reconciliation,
2 internal and external audits, and Michigan Public Service Commission (“MPSC” or
3 the “Commission”) financial and operational reporting. My current position is State
4 Regulatory Affairs Project Specialist. In this position, I am responsible for regulatory
5 activities for MGUC, including: (1) ensuring MGUC’s compliance with all MPSC
6 orders; and (2) acting as a liaison for the Company with the MPSC Staff and
7 intervenors. In addition to these duties, I am responsible for preparing analyses related
8 to and setting the Company’s GCR factors, preparing the monthly 45-Day reports, GCR
9 plan and reconciliation filings, as well as Energy Waste Reduction (“EWR”) plan and
10 reconciliation filings.

11

12 **Q. Have you previously testified before any regulatory agency?**

13 A. Yes. I sponsored testimony in previous MGUC GCR plan and reconciliation
14 proceedings (Case Nos. U-20212, U-20240, U-20545 and U-20818). I also sponsored
15 testimony in MGUC’s EWR plan and reconciliation proceedings (Case Nos. U-20430
16 and U-20709).

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

**TESTIMONY
OF
SHANNON L. BURZYCKI
PART II**

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

2 A. The purpose of my direct testimony is to support the development and presentation of
3 MGUC’s rate design and related proposed tariff changes and to introduce MGUC’s
4 proposed Main Replacement Program (“MRP”) Rider surcharges for the years 2023
5 through 2027. My testimony will include the calculation of the MRP revenue
6 requirement and proposed MRP surcharges.

7
8 **Q. Are you sponsoring any exhibits in this proceeding?**

9 A. Yes, I am. I am sponsoring the following Schedules to Exhibit A-16:
10 1. Schedule F2.1, Summary of Present and Proposed Revenue by Rate
11 Schedule Including Cost of Gas;
12 2. Schedule F2.2, Summary of Present and Proposed Revenue by Rate
13 Schedule Excluding Cost of Gas;
14 3. Schedule F3.1, Present and Proposed Revenue Detail Including Cost of
15 Gas;
16 4. Schedule F3.2, Present and Proposed Revenue Detail Excluding Cost of
17 Gas;
18 5. Schedule F4, Comparison of Present and Proposed Monthly Bills; and
19 6. Schedule F5, Summary of Tariff Changes and Proposed Revised Tariff
20 Sheets.

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 I am also sponsoring the following exhibits that relate to the MRP Rider:

2 Exhibit A-20 Proposed MRP Revenue Requirement; and

3 Exhibit A-21 Proposed MRP Customer Surcharges.

4 **Q. Did you cause these exhibits to be prepared?**

5 A. Yes, I did.

6

7 **Q. Please describe Schedule F2.1 of Exhibit A-16.**

8 A. Schedule F2.1 of Exhibit A-16 is a one page summary showing for each rate schedule
9 the:

- 10 1. Revenues on Present Rates, including the cost of gas,
11 2. Revenues on Proposed Rates, including the cost of gas,
12 3. The proposed rate increase in dollars, including the cost of gas, and
13 4. The proposed rate increase in percent, including the cost of gas.

14

15 **Q. Please describe Schedule F2.2 of Exhibit A-16.**

16 A. Schedule F2.2 of Exhibit A-16 is a one page summary showing for each rate schedule
17 the:

- 18 1. Revenues on Present Rates, excluding the cost of gas,
19 2. Revenues on Proposed Rates, excluding the cost of gas,
20 3. The proposed rate increase in dollars, excluding the cost of gas, and
21 4. The proposed rate increase in percent, excluding the cost of gas.

22

23 **Q. Please describe Schedule F3.1 of Exhibit A-16.**

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 A. Schedule F3.1 of Exhibit A-16 shows a detailed computation by billing determinant
2 for each rate schedule of the:

- 3 1. Revenues at Present Rates, including the cost of gas, and
4 2. Revenues at Proposed Rates, including the cost of gas.

5

6 **Q. Please describe Schedule F3.2 of Exhibit A-16.**

7 A. Schedule F3.2 of Exhibit A-16 shows a detailed computation by billing determinan
8 for each rate schedule of the:

- 9 1. Revenues at Present Rates, excluding the cost of gas, and
10 2. Revenues at Proposed Rates, excluding the cost of gas.

11

12 **Q. What rates were used to calculate revenues at present rates for the above-**
13 **described schedules?**

14 A. The Company used the rates approved by the Commission in MGUC's last rate case
15 (Case No. U-17880, final order dated December 11, 2015) to the test year billing
16 determinants to calculate revenues.

17

18 The cost of gas component of \$3.016 per Mcf was derived from Witness Nelson's
19 Cost of Service Study ("COSS") (total gas costs of \$65,313,503 divided by sales of
20 18,134,581 Mcf).

21

22 **Q. Please describe Schedule F4 of Exhibit A-16.**

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1 A. Schedule F4 of Exhibit A-16 is a comparison of typical monthly bills under present
2 and proposed rates for each rate class.

3

4 **Q. Please describe Schedule F5 of Exhibit A-16.**

5 A. Schedule F5 of Exhibit A-16 is a Summary of Tariff Changes along with the
6 proposed revised tariff sheets in redline format.

7

8 **Summary of the Proposed Rate Increases**

9 **Q. Please summarize MGUC's proposed overall rate increases by service offering.**

10 A. The following table summarizes the proposed revenue increases in dollars and present
11 rates. Revenues include the cost of gas.

12

13

MGUC Rate Schedule	Revenue Increase \$	Revenue Increase %
Residential	\$7,062,877	8.2%
General Service	4,410,346	11.9%
Special Contract	85	0.1%
Transport	1,252,952	16.2%
Aggregated - Residential	1,130	15.3%
Aggregated - General Service	317,386	29.6%
Choice – Residential	1,031,963	17.3%
Choice - General Service	1,050,818	33.3%
TOTAL MGUC	\$15,127,557	10.7%

14

15 The detail underlying these proposed rates can be found in Schedule F3.1 of Exhibit
16 A-16.

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1

2 **Q. Is MGUC proposing to maintain its existing rate structure for each of these**
3 **service offerings?**

4 A. Yes, each offering still includes a fixed monthly charge and a volumetric distribution
5 charge. Monthly administrative charges also continue to apply to customers using
6 transportation and aggregated services.

7

8 **The Development and Presentation of the Proposed Rate Design**

9 **Q. What factors did MGUC consider when developing its proposed rate design?**

10 A. The following factors were considered when developing the proposed rate design:

- 11 1. The COSS sponsored by Witness Nelson, specifically Exhibit A-16, Schedule
12 F1.3;
- 13 2. The movement of customer rates toward the actual cost of service;
- 14 3. The minimization of cross-subsidizations between rate schedules; and,
- 15 4. The addition of a medium-size commercial class to the existing small and
16 large size classes.

17

18 **Q. Please explain how the COSS influenced the proposed rate design.**

19 A. Consistent with cost causation, and sound economic and ratemaking principles,
20 MGUC is proposing to revise its rate structure to more closely reflect the actual cost
21 of providing distribution service to the various customer classes, as calculated by the
22 COSS sponsored by Witness Nelson and shown in Exhibit A-16, Schedule F 1.3. To
23 that end, MGUC is proposing to change its monthly customer and volumetric charges

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1 to better match the monthly fixed costs incurred by MGUC in providing services to
2 these customers.

3

4 **Q. Please explain how the cost similarities and differences inherent to providing**
5 **distribution services to system sales, transportation and Choice customers**
6 **influenced the proposed rate design.**

7 A. MGUC's rate design is based upon the following conclusions from the COSS:

- 8 1. The only significant fixed cost difference between providing distribution
9 services to a transportation customer as compared to providing
10 distribution services to a system sales customer with the same load
11 characteristics is the cost associated with administering the more
12 complicated transportation accounts and managing daily balancing.
13
14 2. The only significant variable, "per Mcf," or volumetric cost difference
15 between providing distribution services to a system sales customer as
16 compared to providing distribution services to transportation and Choice
17 customers with the same load characteristics is the cost associated with
18 administering the gas supply and procurement functions.
19

20 These assumptions are reflected in the grouping of rate schedules in Witness
21 Nelson's Exhibit A-16, Schedules F1.1 thru F1.5.

22

23 **Q. Are the assumptions listed above reasonable?**

24 A. Yes, because they lead to a reasonable match between cost causation and cost
25 recovery.

26

27 **Monthly Customer Charges**
28 **Q. Please describe the Customer Charge.**

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1 A. The Customer Charge is designed to recover a portion of the fixed costs of
2 transporting gas across the MGUC distribution system. In the rate design proposed
3 here, all customers in the same class have equal customer charge fees, as shown on
4 Schedules F3.1 and F3.2 of Exhibit A-16.

5
6 **Q. Are you proposing changes to the monthly customer charges?**

7 A. Yes. The following table summarizes those changes.

8

MGUC Customer Class	Monthly Fixed Charge		Admin Charge	
	Current	Proposed	Current	Proposed
Residential	\$ 13.00	\$ 14.75		
General Service - Small	35.00	47.50		
General Service - Medium		135.00		
General Service - Large	425.00	425.00		
Special Contract	7,983.25	7,983.25		
TR-1 Transport	400.00	600.00	\$450.00	\$600.00
TR-2 Transport	1,800.00	2,000.00	450.00	600.00
TR-3 Transport	2,600.00	2,700.00	450.00	600.00
Aggregated - Residential	13.00	14.75	21.50	21.50
Aggregated - General Service - Small	35.00	47.50	21.50	21.50
Aggregated - General Service - Medium		135.00	21.50	21.50
Aggregated - General Service - Large	425.00	425.00	21.50	21.50
Choice - Residential	13.00	14.75		
Choice - General Service - Small	35.00	47.50		
Choice - General Service - Medium		135.00		
	425.00	425.00		
Choice - General Service – Large				

9

10 In addition to the creation of a medium-size General Service class in all of the
11 commercial & industrial (“C&I”) service offerings at a higher fixed charge than the
12 small-size class, MGUC has proposed increases to most customer classes’ monthly
13 Customer Charge and the monthly administrative charge for transportation customers.

1 The only proposed Customer Charges that MGUC proposes to remain unchanged are
2 for the General Service-Large class. This was done in order to accommodate a
3 breakeven point at 8,300 Mcf/year between the medium and large classes.

A. Transportation customers pay a monthly meter Customer Charge. In addition, Transportation customers pay a monthly Administrative Charge. This fee recovers the costs associated with administering the more complicated transportation accounts. Since 2016, Transportation customers have been required to balance their deliveries and consumption on a daily basis. Customers that aggregate their accounts for billing purposes under the Aggregated services also pay a monthly Administrative Charge in addition to the appropriate Customer Charge for their class.

15 Q. Please describe the proposed distribution rates.

19 Q. Please describe the distribution service volumetric fee component in the
20 distribution rates.

A. The distribution service volumetric fee component recovers any remaining fixed costs that are not recovered through the customer charge as well as the variable costs of transporting gas across MGUC's distribution system. In the rate design proposed

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1 here, all customers in the same class have equal distribution volumetric fees, as
2 shown on Schedules F3.1 and F3.2 of Exhibit A-16.

3

4 **Q. Is it reasonable for system sales customers in the same class to pay the same**
5 **distribution service volumetric fee?**

6 A. Yes, it is. Due to the robust nature of MGUC's distribution system, the likelihood of
7 interruption due to distribution system constraints is small. Therefore, it is reasonable
8 for all customers in the same class to pay the same distribution service volumetric fee
9 component.

10

11 **Q. Please describe the Gas Supply Acquisition component of the distribution rates.**

12 A. The Gas Supply Acquisition component is designed to recover the costs associated
13 with administering MGUC's gas merchant function.

14

15 MGUC has calculated the costs associated with administering the gas merchant
16 function to be equal to \$1,145,077 for the 2022 projected test year. Specifically, the
17 gas merchant function costs primarily include the costs associated with the Gas
18 Supply Department, along with the applicable taxes and Administrative and General
19 ("A&G") expense loadings. This equates to a charge of approximately \$0.0631 per
20 Mcf for GCR customers.

21

22 **Q. Is it reasonable for system sales customers to pay a Gas Supply Acquisition**
23 **component while transportation and Choice customers do not?**

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1 A. Yes, it is. System sales customers are directly benefiting from MGUC's gas
2 merchant function, it is reasonable for these customers to pay a Gas Supply
3 Acquisition component for this service. Transportation and Choice customers receive
4 this service from their own suppliers, not MGUC, and are charged accordingly by
5 their suppliers.

6

7 **Movement of the Customer Charge Toward Cost of Service**

8 **Q. What is MGUC's proposed Customer Charge for Residential service?**

9 A. MGUC's current Monthly Customer Charge is \$13.00 for residential customers. The
10 COSS, prepared by Witness Nelson (specifically Schedule F1.5 of Exhibit A-16),
11 however, supports a Monthly Customer Charge of \$25.09 for a residential customer. In
12 an effort to moderate the amount of the increase, MGUC is proposing that the
13 Residential Monthly Customer Charge only be increased to \$14.75. While this is well
14 below the \$25.09 supported by the COSS, it does represent an 8.2% increase over the
15 current rate.

16

17 **Q. Why is MGUC proposing an increase to the Residential Customer Charge?**

18 A. Because a significant amount of revenue collection varies with the volumetric
19 distribution rate under MGUC's current rate design, MGUC collects more revenue to
20 cover fixed costs when customers use more gas and less revenue to cover fixed costs
21 when customers use less gas. MGUC believes it is appropriate to recover fixed costs
22 through the Customer Charge consistent with the fixed nature of the costs that are
23 incurred. Under MGUC's proposal, not only would the proposed Customer Charge

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1 be more aligned with cost causation, but it would also reduce the volatility in
2 customer bills since a larger portion of the total bill will be fixed each month and will
3 fluctuate based on changes in weather or other customer usage patterns. Customers
4 will continue to receive appropriate price signals based on their consumption of
5 natural gas, and this proposal will serve to reduce the cost-shifting from low load
6 factor customers to higher load factor customers.

7
8 **Q. How does MGUC's proposed Residential Customer Charge compare with other**
9 **gas utilities in Michigan?**

10 A. With regards to other gas utilities in Michigan, the current residential fixed charge
11 rates range from a low of \$5.00 per month for UMERL customers to \$12.60 per
12 month for Consumers Energy customers. DTE's most recent general rate case filing
13 proposes a \$14.40 residential increase.

14
15 **Current Residential Rate Structure and Cost Recovery**

16 **Q. Please describe MGUC's current Residential rate structure and cost recovery.**

17 A. Currently the Residential rate class is subject to a monthly Customer Charge of
18 \$13/month (\$0.4274/day) as well as a Distribution Charge of \$1.5871/ Mcf. A typical
19 residential customer uses 82 Mcf for a calendar year with "normal" weather. Under
20 these rates a typical residential customer pays \$156 a year in Customer Charges, \$130
21 for Distribution Charges, and \$6 for Gas Acquisition Charges, which totals \$293
22 annually for local distribution services only. Residential sales customers are also
23 subject to the GCR factor which recovers MGUC's actual costs of natural gas and the

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costs to transport the gas from the producers to the Company gate stations in its service territory. Using a GCR factor of \$3.6016/Mcf, a customer using 82 Mcf would have an annual gas charge of \$295. Adding the \$293 for distribution service, and the \$295 for the cost of gas, a typical Residential sales customer has an annual bill of \$588.

Q. Please discuss the distribution portion of the typical Residential annual bill.

A. The costs of providing natural gas distribution services including meter reading, billing, collections, depreciation and return are practically 100% fixed and do not vary with the amount of gas actually consumed and purchased by customers. However, while virtually all of the distribution costs are fixed, MGUC's current rate design does not reflect this: of the \$293, only \$156 is collected by the monthly Customer Charge, or approximately 53%, while 47% is recovered on a volumetric basis by the Distribution Charge. Therefore, since there is a volumetric component in the current rate design, the collection of MGUC's base rate revenue requirement is affected by the weather, making the Company a seasonal, weather-dependent business. Under MGUC's proposal, by reducing the volumetric component the impact of weather can also be reduced from the perspectives of both the customers and the Company.

Benefits of Higher Monthly Fixed Charges

Q. Are there benefits to customers for increasing the amount of fixed costs collected in the monthly Customer Charge and decreasing the amount collected by the volumetric Distribution Charge?

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1 A. Yes. As previously discussed and as reflected in the COSS, rates that are better aligned
2 with cost causation provide more equitable or fair treatment of customers. Customers
3 also will enjoy a higher degree of bill certainty and will have costs spread out more
4 during the year vs. having higher costs during the winter months when their
5 consumption is the highest. Under the current pricing structure, recovering almost half
6 of the fixed cost of distribution service by a variable charge provides unnecessary
7 increases in bill impacts during the colder than normal winters.

8
9 **Q. Can you quantify the impact of a higher monthly Customer Charge for a typical**
10 **Residential customer during a colder than normal winter?**

11 A. While a typical Residential customer uses 82 Mcf annually under normal weather, the
12 same customer may use 103 Mcf annually during a colder than normal winter (the
13 average residential customer used 103 Mcf in the year that included the 2013-14 colder-
14 than-normal winter). With MGUC's proposed Customer Charge of \$14.75 per month,
15 a Distribution Charge of \$1.9363 per Mcf, a typical Residential customer using 103
16 Mcf would pay \$383 in annual distribution charges or \$42 more than the \$341 in annual
17 distribution charges proposed for an average customer using 82 Mcf annually as
18 reflected on Exhibit A-16, schedule F3.2..

19
20 **Q. Can you provide more information on how this rate design impacts customers**
21 **with varying amounts of annual consumption?**

22 A. Yes. Schedule F4 of Exhibit A-16 illustrates the impacts for various consumption
23 levels.

24

1 **Q. Will increasing the monthly Residential Customer Charge provide a disincentive**
2 **to conserve natural gas?**

11

12 **Q. Can you provide some examples of low use residential heating customers?**

17

18 **Cross-Subsidization Between Rate Schedules**

21 A. Witness Nelson's Schedule F1.2 of Exhibit A-16, MGUC's 2022 Projected COSS –
22 Detailed Summary indicates that the Residential classes (General Service, Customer

16

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Choice, and Aggregated) plus Transport TR-2 and TR-3 classes are subsidized by the other rate schedules. With MGUC's proposed rate design, MGUC has attempted to reduce the amount of cross-subsidization between the rate schedules by increasing the amount of revenue collected from these rate schedules. MGUC has also proposed a new General Service-Medium class. Although MGUC's rate design does not eliminate all cross-subsidization between rate schedules, it provides appropriate movement toward that goal while considering rate shock and other factors.

Q. In addition to reducing cross-subsidization between rate classes, what other goals did MGUC strive for in developing its rate design?

A. As previously referenced in my testimony, MGUC proposes to add a medium-size C&I class in addition to the existing small and large classes and require customers to be placed in the appropriate class for their size. This will enable the Company to ensure that customers are paying the lowest cost rate for their level of consumption. The creation of the new class requires that rates be designed with appropriate breakeven points. MGUC targeted a breakeven point of 3,300 Mcf/year to move a customer from small to medium class and 8,300 Mcf/year to move a customer from medium to large class. Rates were designed to ensure that the total cost to the customer was the same under either class at each breakeven point.

An additional goal used by MGUC was the concept of gradualism. While it would be reasonable to set both fixed and variable rates at exactly the cost of service for each class and service, it is not always desirable to promote what might be significant rate

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1 changes at one time. Accordingly, the Company attempted to minimize some of the
2 rate adjustments in this proposal in some classes with the intention to reduce cross
3 subsidization.

4

5 **Q. Did MGUC perform a breakeven point analysis for any service offerings other**
6 **than the general service classes?**

7 A. Yes. Breakeven point analysis was also used in the development of the three
8 Transportation classes TR-1, TR-2 and TR-3. The breakeven point between the TR-1
9 and TR-2 class is 57,500 Mcf/year and the breakeven point between the TR-2 and
10 TR-3 class is 571,400 Mcf/year. Even though these breakeven points are proposed to
11 be different than those approved in MGUC's last rate case (56,300 Mcf/year and
12 660,000 Mcf/year, respectively) the Company does not expect that any customers
13 would move from one class to another given these new breakeven points.

14

15 **Q. Please explain what is meant by a breakeven point.**

16 A. The term "breakeven point" refers to the level of volumetric usage where the total
17 amount of revenue collected from the customer at one rate class would equal the total
18 revenue collected under another rate class. In the Company's last rate case, for
19 instance, the same breakeven point of 3,300 Mcf/year was approved in the rate design
20 to distinguish between a small commercial and large commercial customer.

21

22 **Q. Is it necessary in certain circumstances to realign breakeven points from one**
23 **rate case to another?**

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1 A. Yes. In fact, MGUC has proposed to do so in this case with the Transportation
2 classes. Realignments can be necessary in order to ensure that individual rate classes
3 remain consistent with their cost-basis per the COSS.

4
5 **Q. Why is it important to incorporate breakeven point analysis in rate design?**

6 A. Incorporating economic breakeven points between rate classes is important for
7 several reasons, which I note below:
8 1. Provides transparency for customers, allowing them to know which rate is best for
9 their usage requirement;
10 2. Reduces the administrative and contractual burden of moving customers between
11 rate classes;
12 3. Stabilizes and minimizes rate shifting. Frequent shifts from rate class to rate class
13 can cause volatility in the utility's revenue collection, making it difficult to
14 accurately predict revenues for planning purposes and for future ratemaking
15 purposes; and
16 4. Allows for greater precision in designing rates and predicting revenue collections.

17
18 Currently, customers are allowed to move, so long as they are eligible under the terms
19 of the tariff, between rate classes at their discretion even if those rates are not
20 designed to be the lowest possible rate for their level of usage. MGUC now proposes
21 to utilize these breakeven points in its tariff language as a requirement for service.
22 Implementing mandatory size requirements in the class tariffs will enable the
23 Company to assign customers to proper rate classes and provide more certainty of

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1 collecting its authorized rates. An annual usage review will be performed in order to
2 determine if/when it is appropriate to move customers to a new class within the
3 Company's service offering.
4

5 **Q. How will the Company conduct an annual review of rate class assignments for**
6 **its customers?**

7 A. Customers will be evaluated on a calendar year usage basis to determine the class
8 they should be assigned to. We understand that customer usage can change from year
9 to year for a number of reasons – the economy, weather, etc. Therefore, it may be
10 inappropriate and confusing to switch customers back and forth if they happen to
11 routinely fall on or around the breakpoint. MGUC proposes to apply a 10% band to
12 the actual usage for the prior year before moving customers. This means that MGUC
13 will move a customer up to the next class if their annual usage is 10% or more above
14 the breakeven point. Alternatively, MGUC will only move a customer down to a
15 lower consumption rate class if their annual usages was 10% or more below the
16 breakeven point.
17

18 **New Tariff Sheet**

19 **Q. Is MGU proposing any new tariffs?**

20 A. Yes, MGUC is proposing a new Gas Demand Response tariff.
21

22 **Q. Please describe the proposed Gas Demand Response tariff.**

23 A. Pursuant to the Commission's Order in Case No. U-20464, which directed utilities to

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1 propose Gas Demand Response tariffs in their next general rate cases, MGUC is
2 proposing to deploy its existing Customer Notification System (“CNS”), which is
3 currently in use for its Transportation Customers/Suppliers. The CNS is used for the
4 WPS Electric Response Rewards Program, as well as other programs for five other
5 WEC utilities. The CNS notifies customers via e-mail, SMS/text messaging or by a
6 phone call if there is an energy emergency which requires a reduction in gas
7 consumption by the consumer.

8
9 **Q. Why is MGUC proposing to use the CNS platform?**

10 A. Because the CNS is established and has demonstrated track record, MGUC believes it
11 will be an efficient, cost-effective means to notify customers. Based upon a
12 customer’s preference, multiple methods of notification can be requested and up to
13 two individuals per account can be notified. Each customer contact can be notified
14 by way of up to 2 email addresses, 3 phone numbers and 1 SMS/text messaging
15 number.

16
17 **Q. Explain the population of customers that would be notified in an energy**
18 **emergency.**

19 A. The CNS has the flexibility to be configured by region in addition to rate type. This
20 means that if there is an energy emergency in a specific area the Company can notify
21 only those customers in the designated region. Conversely, all customers on the
22 Demand Response Program can be notified if necessary.

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1 **Q. Did MGUC consider utilizing a Smart Thermostat platform?**

2 A. Yes, MGUC did consider using a Smart Thermostat platform. However the CNS was
3 chosen as the most cost-effective mechanism to initiate and potentially expand the
4 proposed pilot in the future. MGUC believes this is the most prudent approach while
5 still providing a reasonable Gas Demand Response Pilot Program.

6

7 **Q. Has MGUC performed a pilot program for Residential and C&I customers for**
8 **Gas Demand Response?**

9 A. No.

10

11 **Q. Has MGUC identified a customer participation limit for this proposed Pilot**
12 **Program?**

13 A. Yes, the Company is proposing an initial limit of 85 customers for participation in the
14 pilot program. This smaller customer participation limit was established in order to
15 acquire measurement statistics and other necessary data in order to access the
16 effectiveness of the proposed program and determine any future amendments.

17

18 **Q. When will MGUC begin enrolling customers to participate?**

19 A. The Company will make customers aware of the program by bill inserts and will
20 begin to enroll customers prior to the fall of 2022 heating season.

21

22 **Q. How will MGUC incentivize Residential and C&I customers to participate?**

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1 A. The Company will offer a one in ten chance to win a \$50 Gift Card at the beginning
2 of the heating season and a \$25 Gift Card at the end of the heating season. Offering
3 gift cards to customers is an approach that has worked with other utilities for demand
4 response pilots with satisfactory results.

5

6 **Q. How much notification will MGUC provide to customers before an energy event**
7 **is called?**

8 A. The Company will provide a minimum of 24-hour notice before an event is called and
9 again one hour before the event. The 24-hour notice will provide ample time for a
10 customer to be aware, prepare and potentially share the event information with other
11 household members. The one-hour notice will then remind the customer that they are
12 being asked to reduce their usage in response to the identified event.

13

14 **Q. How long will MGUC call the events requesting customers to reduce their**
15 **usage?**

16 A. The Company will request a 2 to 8 hour window to reduce usage.

17

18 **Q. How many degrees reduction will MGUC request when an event is called?**

19 A. The Company will request a 1 to 4 degree reduction in order to reduce the customer's
20 usage.

21

22 **Q. What are the estimated costs of adding the proposed customers to the CNS?**

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1 A. Everbridge provides third-party software that delivers the notifications and charges
2 WEC an annual fee based on a set number of customer contacts. MGUC currently
3 receives an allocation of costs for the Transportation Customers/Suppliers which is
4 approximately \$10,500 annually. Each customer requires a contact in the CNS. At
5 this time, the cost to purchase an additional 1,000 customer contacts is \$9.97 per
6 contact. Other costs to implement the Gas Demand Response Pilot Program include
7 IT labor for programming changes to the CNS, MGUC labor associated with
8 administering and configuring the CNS enhancements, resources to create reporting
9 and to add contacts into the Customer Notification System. The total cost of this
10 internal labor is estimated to be approximately \$100,000.

11

12 **New Main Replacement Program (MRP) Rider Surcharge**

13 **Q. Please discuss the Company's Main Replacement Program.**

14

15 A. As discussed in the testimony of Witness Lee, MGUC has identified future
16 main/pipeline replacement projects that it plans to implement after the 2022 test year
17 as part of the Company's continued efforts to provide reliable, safe natural gas service
18 to its customers. Similar to SEMCO Energy Gas Company, the Company would like
19 authority to implement a monthly per customer meter charge applicable to all of
20 MGUC's customer classes to recover the annual incremental capital investment for a
21 five-year period. In view of the Company's (i) relatively small size, (ii) its substantial
22 capital spending, and (iii) the non-revenue producing nature of these necessary capital
23 projects, it is reasonable to authorize MGUC to collect the capital-related costs before
24 they are placed in rate base. MGUC believes that because the driving force for filing

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1 this rate case relates to its past capital spending projects, with the implementation of
2 the MRP, the Company may be able extend the time for filing its next rate case.

3

4 **Q. Please describe page 1 of Exhibit A-20.**

5 A. Exhibit A-20 calculates the 2023 through 2027 annual revenue requirement for each
6 year that was used to develop the annual customer surcharges, including the initially-
7 proposed surcharge for 2023. The yearly incremental investment associated with the
8 MRP is illustrated on line 1 of the exhibit. Lines 2-6 calculate the average net rate
9 base. The average net rate base is calculated by taking the cumulative capital
10 investment on line 2 and subtracting out the accumulated depreciation and
11 accumulated deferred taxes on lines 3 and 4. The result is the ending next rate bases
12 on line 5 which is divided by two and results in the average net rate base for that year
13 on line 6. The average annual net rate base is then multiplied by the capital rate of
14 8.68% to calculate the pre-tax return on net rate base shown on line 7. The
15 depreciation expense and property taxes are then added to the return on net rate based
16 to derive the total annual revenue requirements illustrated on line 11 for each year.

17

18 **Q. What is the basis for the 8.68% capital charge rate?**

19 A. The 8.68% capital charge rate is the Company's proposed pre-tax carrying cost and is
20 based on the weighted rate of debt, preferred stock, equity and associated taxes
21 reflected in the testimony of Witness Zgonc.

22

23 **Q. What is the basis for the 2.92% book depreciation rate?**

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1 A. The 2.92% book depreciation rate is the weighted average depreciation rate for all of
2 the capital investment in the MRP through December 2027.

3

4 **Q. What is the basis for the property tax millage rate?**

5 A. The millage rate is the weighted average millage rate for the municipalities in which
6 the forecasted projects will be located for all of the capital investment in the MRP
7 through December 2027.

8

9 **Q. Please describe page 2 of Exhibit A-20.**

10 A. Page 2 of Exhibit A-20 is used to calculate the accumulated deferred taxes and the
11 property taxes. The deferred taxes are calculated using the 20 year MACRS tax
12 depreciation table and the weighted average 2.92% book depreciation rate for the
13 MRP.

14

15 **Q. Please explain Exhibit A-21.**

16 A. Exhibit A-21 calculates the estimated annual MRP surcharges based on the forecasted
17 annual revenue requirement from Line 11 of Exhibit A-20, page 1. All allocation
18 factors on the exhibit are based on the 2022 Cost of Service Study supported by Witness
19 Nelson. The Company proposes that these surcharges remain in effect until the earlier
20 of either: (i) base rates are addressed in a future contested case addressing the MRP, or
21 (ii) December 31, 2027.

22

23 **Q. Are all customer classes calculated using this method?**

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1 A. Existing rate classes were calculated using this method. For the proposed Medium
2 General Service class an average allocation of the Small General Service and Large
3 General Service was used. For example, the Small General Service rate of \$0.15 plus
4 the Large General Service rate of \$2.42 totalling \$2.57 is then divided by two
5 equalling \$1.29 ($\$0.15 + \$2.42 = \$2.57$) $\$2.57/2 = \$1.29$.

6

7 **Q. Is the Company proposing a reporting requirement?**

8 A. MGUC also proposes filing in this docket an annual MRP report by April 1st of the
9 year following the program year, detailing the annual capital spend.

10

11 **Q. Is MGUC proposing that the MRP Rider surcharge be updated each year?**

12 A. Yes. Beginning in 2024, MGUC proposes annually filing in this docket by
13 September 1st, the proposed surcharge rate for the following year. Included in this
14 proposed surcharge filing will be the revenue requirement and the underlying
15 assumptions for the surcharge proposed for the following program year as well as an
16 adjustment to the surcharge to refund any over-recovered amount or collect any
17 under-recovered amount, as reported in the most recently filed MRP report.

18

19 **Q. Why is MGUC proposing that approach?**

20 A. The proposed surcharge is based on forecasted capital costs of projects that will not
21 be undertaken for 2 years or more into the future. By updating the revenue
22 requirements and the surcharge each year, the Company can leverage more current
23 cost estimates for the subsequent year's surcharge and adjustments for actual costs

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 and recoveries for the prior year's activity. This will ensure that customers only pay
2 for the actual costs of the projects included in the scope of the proposed rider.

3

4 **Q. How does MGUC propose to address any difference that exists as of December**
5 **31, 2027, in the amounts recovered through the MRP Rider Surcharge and the**
6 **revenue requirement authorized for recovery?**

7 A. If there is a difference of the revenue requirement associated with this surcharge and
8 the amount collected as of December 31, 2027 and MGUC has not filed for a TY2028
9 rate case, this amount will be maintained in a regulatory account to be returned to or
10 collected from customers in the Company's next rate case or other proceeding
11 addressing the surcharge.

12

13 **Q. Are you sponsoring tariff sheets relective of the proposed MRP rider?**

14 A. Yes, see pages 26-29 of Exhibit A-16, Schedule F5 which reflect the MRP Rider and
15 initial surcharge proposed for 2023.

16

17 **Proposed Tariff Sheet Changes**

18 **Q. Please explain Schedule F5 of Exhibit A-16.**

19 A. Schedule F5, pages 1-2 summarize the changes being proposed for MGUC's natural
20 gas tariff. Pages 3-62 are redlined versions of the proposed tariff sheets.

21

22 **Q. What revision is MGUC proposing on Tariff Sheet No. A-6.00?**

23 A. MGUC is providing an updated Index.

24

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 **Q. What revision is MGUC proposing on Tariff Sheet No. A-12.00?**

2 A. MGUC is providing an updated service territory map which includes the Vector
3 Interconnect pipeline and the Otsego District Office replacement in Allegan.

4

5 **Q. What revision is MGUC proposing on Tariff Sheet No. C-13.00?**

6 A. MGUC is updating the lettering in the Curtailment of Gas Service, Nominations and
7 Waivers from “e)” to “c)”.

8

9 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. C-20.00 through C-
10 21.00?**

11 A. All references related to Centrally Metered Installations have been updated pursuant
12 to rule R 460.20355 Master Meter Systems per the 24th Edition Michigan Gas Safety
13 Standards Guide.

14

15 **Q. What revisions are MGUC proposing on Tariff Sheet No. C-28.00?**

16 A. Similar to C-20.00 through C-21.00 references related to Centrally Metered
17 Installations have been updated pursuant to rule R 460.20355 Master Meter Systems
18 per the 24th Edition Michigan Gas Safety Standards Guide. In addition, language
19 clarifying that all installations will be approved in accordance with all applicable
20 codes and standards.

21

22 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. C-29.00 and C-30.00?**

23 A. Removed reference to Rule C7.5, "Company's Installation".

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1

2 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. C-34.00 and C35.00?**

3 A. The Company is seeking to insert clarifying language under its Customer Attachment
4 program to include Small General Service and Medium General Service to the
5 existing language. The reason for this language is to protect the Company from
6 default on the part of commercial customers who may go out-of-business before
7 paying their full share of costs associated with their businesses.

8

9 **Q. What revision is MGUC proposing on Tariff Sheet No. C-36.00?**

10 A. The Company is updating the Carrying Cost Rate per the proposed rate case reflected
11 in the testimony of Witness Zgonc on Exhibit A-14, Schedule D-1.

12

13 **Q. What revision is MGUC proposing on Tariff Sheet No. C-37.00?**

14 A. The Company is updating the Discount Rate per the proposed rate case reflected in
15 the testimony of Witness Zgonc on Exhibit A-14, Schedule D-1.

16

17 **Q. What revision is MGUC proposing on Tariff Sheet No. C-38.00 to C-45.00?**

18 A. The Company is updating the Customer Attachment Program project areas.

19

20 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. D-1.02 to D-1.03?**

21 A. The Company is removing the Tax Cut And Jobs Act credits because those values
22 will not be incorporated into base rates.

23

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. D-1.04 to D-1.07?**

2 A. The Company is adding the MRP Surcharge Rider.

3

4 **Q. What revisions are MGUC proposing on Tariff Sheet No. D-6.00?**

5 A. The Company has updated its Customer and Distribution charges per its proposed rate
6 design. The Company is proposing to increase the Residential Customer Charge to
7 \$14.75 per month, and the Distribution charge to \$1.9363 per Mcf.

8

9 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. D-8.00-D-16.00?**

10 A. The Company has reoriented existing pages to propose the Medium General Service
11 rate class per the proposed rate design. For Small General Service, the Company is
12 proposing a Customer Charge of \$47.50, a Distribution charge of \$2.0853 per Mcf
13 and a volumetric breakpoint of usage below 3,300 Mcf. For Medium General
14 Service, the Company is proposing a Customer Charge of \$135.00 per month, a
15 Distribution charge of \$1.7741 per Mcf and volumetric breakpoints of 3,300 – 8,300
16 per Mcf. For Large General Service, the Company is proposing a Customer Charge
17 of \$425.00 per month, a Distribution charge of \$1.3577 per Mcf and volumetric
18 breakpoints of above 8,300 Mcf.

19

20 **Q. What is MGUC proposing on Tariff Sheet No. D-17.00?**

21 A. The Company is proposing, for the Gas Lighting Rate, that the Residential
22 Distribution Charges be removed. The Commercial Distribution Charges have been

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1 updated consistent with MGUC's proposed rate design. The new rate is \$2.0853 per
2 Mcf.

3

4 **Q. What revisions are MGUC proposing on Tariff Sheet Nos. E-5.00 and E-6.00?**

5 A. The name and website link of the former electronic bulletin board address have been
6 removed and replaced with an abbreviation for the electronic bulletin board of EBB.
7 In addition, E-5.00 has updated the nomination deadlines to be in accordance with
8 NAESB Standard 1.3.2.

9

10 **Q. What revisions is MGUC proposing on Tariff Sheet No. E-12.00?**

11 A. MGUC removed the language specifying data will be made available within two
12 hours following the gas day. Customers seeking real time volumetric flow data can
13 install the appropriate equipment to duplicate invoice quality data, at the customer's
14 expense.

15

16 **Q. What revisions is MGUC proposing on Tariff Sheet No. E-13.00?**

17 A. MGUC removed the reference to sheet D-1.02 and D-1.03, added the telemetering
18 charge to the rate table for visibility and added usage break points for each tier of
19 transportation.

20

21 **Q. What revisions is MGUC proposing on Tariff Sheet No. E-14.00?**

22 A. MGUC added the MRP Surcharge Rider and revised sheet references for
23 Supplemental Charges.

DIRECT TESTIMONY AND EXHIBITS OF
SHANNON L. BURZYCKI

1

2 **Q. What revisions is MGUC proposing on Tariff Sheet No. E-16.00?**

3 A. MGUC added clarifying language specifying the responsibilities of the Supplier's and
4 Customer's notifications to ensure accurate and timely customer transfers.

5

6 **Q. What revision is MGUC proposing on Tariff Sheet No. F-2.00?**

7 A. MGUC is clarifying language as it pertains to the daily schedule of quantities for
8 delivery of gas into the Company's system.

9

10 **Q. What revision is MGUC proposing on Tariff Sheet No. F-3.00?**

11 A. MGUC has updated the nomination deadlines to be in accordance with NAESB
12 Standard 1.3.2.

13

14 **Q. What revision is MGUC proposing on Tariff Sheet Nos. F-6.00 – F-11.00?**

15 A. MGUC has added Medium Commercial General Service language and references as
16 well as usage break points.

17

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

19 A. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase its retail rates natural)
gas and for other relief.)
_____)

Case No. U-20718

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that Michigan Gas Utilities Corporation (Applicant) or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the “Disclosing Party”; the recipient is the “Receiving Party” (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials. This Protective Order defines “Protected Material” and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. “Protected Material” and Other Definitions

A. For the purposes of this Protective Order, “Protected Material” consists of trade secrets or confidential, proprietary, or commercially sensitive information to be provided by Disclosing Party in materials responsive to Part III of the Commission’s rate case filing requirements approved in Case No. U-18238 and any testimony, exhibits or workpapers describing the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material also includes the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding officer or the Michigan Public Service Commission (MPSC or Commission), in testimony or exhibits filed later in this case, or in arguments of counsel.

2. Information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third-party licensor to disclose consistent with the terms and conditions of this Protective Order.

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a natural gas purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (i.e., before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. “Party” refers to the Applicant, MPSC Staff (Staff), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this Case No. U-20718 under the Commission’s Rules of Practice and Procedure. Mich Admin Code, R 792.10401 et al.

D. “Receiving Party” means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. “Reviewing Representative” means a person who has signed a Nondisclosure Certificate and who is:

1. an attorney who has entered an appearance in this proceeding for a Receiving Party;
2. an attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;
3. an expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or
4. an employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. “Nondisclosure Certificate” means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: 1) the Protected Material; 2) any copy or reproduction of the Protected Material made by any person; and 3) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of

a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to and use of Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding officer shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall mark any information that it considers confidential as “CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED ON [INSERT DATE] IN CASE NO. U-20718.” If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving

Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL — SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20718." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed.

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material.

3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party only to the extent permitted by law. If any person files a request under the Freedom of Information Act with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary, Staff, or the Attorney General shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the MPSC, its Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this

Protective Order. In response to a motion or on its own initiative, the Commission or the presiding officer in this case may revoke a document's protected status after notice and hearing. If the presiding officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, then the Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

A. Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in this Case No. U-20718 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its

Reviewing Representatives—including all copies and notes of Protected Material—or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

B. Notwithstanding the preceding paragraph, Counsel for a Receiving Party may maintain a single confidential file of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding, then it may be used in such a proceeding subject to the issuance of a new Protective Order in that proceeding. The terms of this Paragraph shall apply until the later of (i) the resolution of Applicant's next general natural gas rate case conducted after the conclusion of Case No. U-20718, or (ii) the resolution of any and all Gas Cost Recovery ("GCR") plan or GCR reconciliation cases that may be filed before the resolution of the next general natural gas rate case. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission. Counsel for a Requesting Party may also retain, without time limitation, a single unredacted copy of any Counsel's own briefs (not including any confidential attachments) that contain information derived from Protected Material, subject to continued confidential treatment in accordance with all obligations of this Protected Order.

VI. Limitations and Disclosures

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must—before actually disclosing the

Information do one of the following: 1) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or 2) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

Administrative Law Judge

Case No. U-20718

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

Please Note: The Commission will provide electronic service of documents to all parties in this proceeding.

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Michigan Gas Utilities Corporation Docket No. U- 20718

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman
Address Miller Canfield
One Michigan Avenue, Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4954
Email wellmans@millercafield.com
Date 03/22/2021

Signature: Sherri Wellman

Digitally signed by: Sherri Wellman
DN: CN = Sherri Wellman email =
wellmans@millercafield.com C = AD O = Miller
Canfield
Date: 2021.03.22 12:41:18 -0400

☐ I am not an attorney

☒ I am an attorney whose:

Michigan Bar # is P- 38989

_____ Bar # is: _____
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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Case / Company Name: Michigan Gas Utilities Corporation Docket No. U- 20718

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins
Address Miller Canfield
1 E. Michigan Ave., Ste. 900
City Lansing State MI
Zip 48933 Phone 517-483-4908
Email collinsp@millercanfield.com
Date 03/22/2021

☐ I am not an attorney

☒ I am an attorney whose:

Michigan Bar # is P- 69719

_____ Bar # is: _____
(state)

Signature: Paul Collins

Digitally signed by: Paul Collins
DN: CN = Paul Collins email = collinsp@millercanfield.
com C = AD O = Miller Canfield
Date: 2021.03.22 12:41:37 -04'00'

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

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Case / Company Name: Michigan Gas Utilities Corporation Docket No. U- 20718

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Michigan Gas Utilities Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Michael B. Fisher
Address Miller Canfield
1 E. Michigan Ave., Ste. 900
City Lansing State MI
Zip 48933 Phone 517-483-4949
Email fisher@millercanfield.com
Date 03/22/2021

☐ I am not an attorney

☒ I am an attorney whose:

Michigan Bar # is P- 84781

_____ Bar # is: _____
(state)

Signature: Michael B. Fisher

Digitally signed by: Michael B. Fisher
DN: CN = Michael B. Fisher email =
fisher@millercanfield.com C = US O = Miller Canfield
OU = Attorney
Date: 2021.03.22 12:41:58 -0400

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
MICHIGAN GAS UTILITIES CORPORATION)
for authority to increase retail natural gas rates)
and for other relief.)

Case No. U-20718

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF INGHAM)

Elizabeth H. Kunc, being first duly sworn, deposes and states that on March 22, 2021, she served **Michigan Gas Utilities Corporation's direct case** as electronically filed on this date upon the parties listed below via electronic mail.

Jennifer Utter Heston
Michael E. Moody

jheston@fraserlawfirm.com
moodym2@michigan.gov;
ag-enra-spec-lit@michigan.gov

Elizabeth H. Kunc

Digitally signed by: Elizabeth H. Kunc
DN: CN = Elizabeth H. Kunc email =
kunc@millercanfield.com C = AD O = Miller
Canfield OU = Legal Secretary
Date: 2021.03.22 12:43:15 -04'00'

Elizabeth H. Kunc

Subscribed and sworn before me
on this 22nd day of March, 2021.

Allison Kellogg

Digitally signed by: Allison Kellogg
DN: CN = Allison Kellogg email =
kellogg@millercanfield.com C = US O = Miller Canfield
Date: 2021.03.22 12:43:34 -04'00'

Allison Kellogg, Notary Public
State of Michigan, Shiawassee County
My Commission Expires: 09/03/2025
Acting in the County of Ingham

MPSC Case No. U-20718
MGUC Index of Exhibits

Part	MGUC Exhibit No.	Schedule	Title	Witness
I	A-1	A1	Revenue Deficiency (Sufficiency)	Joseph L. Zgonc
I	A-1	A2	Financial Metrics - Financial Basis	Joseph L. Zgonc
I	A-2	B1	Rate Base	Joseph L. Zgonc
I	A-2	B2	Total Utility Plant	Joseph L. Zgonc
I	A-2	B3	Depreciation Reserve and Other Deductions	Joseph L. Zgonc
I	A-2	B4	Working Capital	Joseph L. Zgonc
I	A-3	C1	Adjusted Net Operating Income	Joseph L. Zgonc
I	A-3	C2	Revenue Conversion Factor	Joseph L. Zgonc
I	A-3	C3	Operating Revenue	Joseph L. Zgonc
I	A-3	C4	Cost of Gas Sold	Joseph L. Zgonc
I	A-3	C5	Operation and Maintenance Expenses	Joseph L. Zgonc
I	A-3	C6	Depreciation and Amortization Expenses	Joseph L. Zgonc
I	A-3	C7	General Taxes	Joseph L. Zgonc
I	A-3	C8	Federal Income Taxes	Joseph L. Zgonc
I	A-3	C9	State Income Taxes	Joseph L. Zgonc
I	A-3	C10	Other (or Local) Taxes	Joseph L. Zgonc
I	A-3	C11	Allowance for Funds Used During Construction	Joseph L. Zgonc
I	A-4	D1	Rate of Return Summary	Joseph L. Zgonc
I	A-4	D2	Cost of Long-Term Debt	Joseph L. Zgonc
I	A-4	D3	Cost of Short-Term Debt	Joseph L. Zgonc
I	A-4	D4	Cost of Preferred Stock	Joseph L. Zgonc
I	A-4	D5	Cost of Common Shareholders' Equity	Joseph L. Zgonc
I	A-5	E1	Annual Service Area Sales by Major Customer Classes and System Output	Jared J. Peccarelli
I	A-11	A1	Revenue Deficiency (Sufficiency)	Joseph L. Zgonc
I	A-11	A2	Financial Metrics - Ratemaking Basis	Joseph L. Zgonc
I	A-12	B1	Projected Rate Base	Joseph L. Zgonc
I	A-12	B2	Total Utility Plant	Joseph L. Zgonc
I	A-12	B3	Depreciation Reserve and Other Deductions	Joseph L. Zgonc
I	A-12	B4	Working Capital	Joseph L. Zgonc
I	A-12	B5	Summary of Actual and Projected Gas Capital Expenditures	Joseph L. Zgonc
I	A-12	B5.1	Underground Gas Storage Capital Expenditures	Joseph L. Zgonc
I	A-12	B5.2	Transmission Capital Expenditures	Joseph L. Zgonc
I	A-12	B5.3	Distribution Plant Capital Expenditures	Joseph L. Zgonc
I	A-12	B5.4	General Capital Expenditures	Joseph L. Zgonc
I	A-12	B5.5	Intangible Capital Expenditures	Joseph L. Zgonc
I	A-13	C1	Adjusted Net Operating Income	Joseph L. Zgonc
I	A-13	C2	Projected Revenue Conversion Factor	Joseph L. Zgonc
I	A-13	C3	Projected Operating Revenue	Joseph L. Zgonc

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Part	MGUC Exhibit No.	Schedule	Title	Witness
I	A-13	C4	Cost of Gas Sold	Joseph L. Zgonc
I	A-13	C5	Projected Operation and Maintenance Expenses	Joseph L. Zgonc
I	A-13	C6	Projected Depreciation and Amortization Expenses	Joseph L. Zgonc
I	A-13	C7	Projected General Taxes	Joseph L. Zgonc
I	A-13	C8	Projected Federal Income Taxes	Joseph L. Zgonc
I	A-13	C9	Projected State Income Taxes	Joseph L. Zgonc
I	A-13	C10	Other (or Local) Taxes	Joseph L. Zgonc
I	A-13	C11	Allowance for Funds Used During Construction	Joseph L. Zgonc
I	A-14	D1	Projected Rate of Return Summary	Joseph L. Zgonc
I	A-14	D2	Cost of Long-Term Debt	Joseph L. Zgonc
I	A-14	D3	Cost of Short-Term Debt	Joseph L. Zgonc
I	A-14	D4	Cost of Preferred Stock	Joseph L. Zgonc
I	A-14	D5	Cost of Common Shareholders' Equity	Joseph L. Zgonc
I	A-14	D6	Summary of Results	Ann E. Bulkley
I	A-14	D7	Proxy Group Selection	Ann E. Bulkley
I	A-14	D8	Constant Growth DCF Model	Ann E. Bulkley
I	A-14	D9	Multi-Stage DCF Model	Ann E. Bulkley
I	A-14	D10	Long-term GDP Growth Rate	Ann E. Bulkley
I	A-14	D11	Capital Asset Pricing Model / Empirical Capital Asset Pricing Model – Value Line and Bloomberg Beta	Ann E. Bulkley
I	A-14	D12	Capital Asset Pricing Model / Empirical Capital Asset Pricing Model – Long-term Average Beta	Ann E. Bulkley
I	A-14	D13	Long-term Average Beta	Ann E. Bulkley
I	A-14	D14	Market Return	Ann E. Bulkley
I	A-14	D15	Bond Yield Plus Risk Premium	Ann E. Bulkley
I	A-14	D16	Size Premium Analysis	Ann E. Bulkley
I	A-14	D17	Capital Expenditures Analysis	Ann E. Bulkley
I	A-14	D18	Regulatory Risk Analysis	Ann E. Bulkley
I	A-14	D19	Flotation Cost	Ann E. Bulkley
I	A-14	D20	Capital Structure Analysis	Ann E. Bulkley
I	A-15	E1	Market Outlook: 5-Year Annual Calendar Gas Forecast by Class	Jared J. Peccarelli
I	A-16	F1.1	Return Summary by Rate Class	Aaron L. Nelson
I	A-16	F1.2	Return Summary by Rate Schedule	Aaron L. Nelson
I	A-16	F1.3	Unbundled Revenue Requirement	Aaron L. Nelson
I	A-16	F1.4	Unbundled Rate Base	Aaron L. Nelson
I	A-16	F1.5	Unbundled Unit Costs	Aaron L. Nelson
I	A-16	F1.6	Return Summary by Rate Class (alternate 1)	Aaron L. Nelson
I	A-16	F1.7	Return Summary by Rate Schedule (alternate 1)	Aaron L. Nelson

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Part	MGUC Exhibit No.	Schedule	Title	Witness
I	A-16	F2.1	Summary of Present and Proposed Revenue by Rate Schedule Including Cost of Gas	Shannon L. Burzycki
I	A-16	F2.2	Summary of Present and Proposed Revenue by Rate Schedule Excluding Cost of Gas	Shannon L. Burzycki
I	A-16	F3.1	Present and Proposed Revenue Detail Including Cost of Gas	Shannon L. Burzycki
I	A-16	F3.2	Present and Proposed Revenue Detail Excluding Cost of Gas	Shannon L. Burzycki
I	A-16	F4	Comparison of Present and Proposed Monthly Bills	Shannon L. Burzycki
I	A-16	F5	Summary of Tariff Changes and Proposed Revised Tariff Sheets	Shannon L. Burzycki
I	A-17	C1	Operation and Maintenance Expenses - Gas Utility - Historical and Forecasted	Joseph L. Zgonc
I	A-17	C2	Known and Measurable Adjustment for Manufactured Gas Plant Remediation	Joseph L. Zgonc
I	A-17	C3	Known and Measurable Adjustment for Underground Storage Expenses - Wells	Joseph L. Zgonc
I	A-17	C4	Known and Measurable Adjustment for Underground Storage Expenses - Other	Joseph L. Zgonc
I	A-17	C5	Known and Measurable Adjustment for Transmission Operations Mains Expense	Joseph L. Zgonc
I	A-17	C6	Known and Measurable Adjustment for Transmission Operations Other Expenses	Joseph L. Zgonc
I	A-17	C7	Known and Measurable Adjustment for Transmission Maintenance of Mains	Joseph L. Zgonc
I	A-17	C8	Known and Measurable Adjustment for Distribution Operations Mains and Service Expenses	Joseph L. Zgonc
I	A-17	C9	Known and Measurable Adjustment for Distribution Operations Other Expenses	Joseph L. Zgonc
I	A-17	C10	Known and Measurable Adjustment for Distribution Maintenance of Mains	Joseph L. Zgonc
I	A-17	C11	Known and Measurable Adjustment for Distribution Maintenance of Measuring and Regulating Station Equipment - General	Joseph L. Zgonc
I	A-17	C12	Known and Measurable Adjustment for Distribution Maintenance of Services	Joseph L. Zgonc
I	A-17	C13	Known and Measurable Adjustment for Distribution Maintenance of Meters and House Regulators	Joseph L. Zgonc
I	A-17	C14	Known and Measurable Adjustment for Customer Accounts Expense - Meter Reading	Joseph L. Zgonc

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I	A-17	C15	Known and Measurable Adjustment for Customer Accounts Expense - Customer Records and Collection	Joseph L. Zgonc
I	A-17	C16	Known and Measurable Adjustment for Customer Accounts Expense - Uncollectible Accounts	Joseph L. Zgonc
I	A-17	C17	Known and Measurable Adjustment for Administrative and General - Injuries and Damages Expenses	Joseph L. Zgonc
I	A-17	C18	Known and Measurable Adjustment for Administrative and General - Employee Pensions and Benefits Expenses	Joseph L. Zgonc
I	A-17	C19	Known and Measurable Adjustment for Administrative and General - Miscellaneous General Expenses	Joseph L. Zgonc
I	A-17	C20	Estimate of Inflation for 2020, 2021, and 2022	Joseph L. Zgonc
I	A-18		Annual Incentive Plan for Non-Executives	Joseph L. Zgonc
I	A-19		2021 MGU Non-Executive Incentive Plan Overview (Confidential and Public Versions)	Joseph L. Zgonc
I	A-20		Proposed MRP Revenue Requirement	Shannon L. Burzycki
I	A-21		Proposed MRP Customer Surcharges	Shannon L. Burzycki
II	N/A		2019 MGU Annual Report to MPSC P-522	
II	N/A		2018 MGU Annual Report to MPSC P-522	
II	N/A		2020 MGU Annual Report to the SEC Form 10-K (February 27, 2020)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (November 6, 2020)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (August 6, 2020)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (May 7, 2020)	
II	N/A		Quarterly Report to Shareholders SEC Form 10-Q (November 7, 2019)	
II	N/A		Bond and Other Financial Prospectuses (Confidential)	
III	N/A		See "Part III Supplemental Data Index"	

Schedule A-1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Revenue Deficiency (Sufficiency)

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Line No.	(a) Description	(b) Source	(c) Total (\$000)
1			
2	Rate Base	Exh. A-2, Sch. B1	\$ 305,953
3			
4	Adjusted Net Operating Income	Exh. A-3, Sch. C1	<u>22,171</u>
5			
6	Overall Rate of Return	Line 4 ÷ Line 2	7.25%
7			
8	Required Rate of Return	Exh. A-4, Sch. D1	<u>5.69%</u>
9			
10	Income Requirements	Line 2 x Line 8	<u>17,408</u>
11			
12	Income Deficiency (Sufficiency)	Line 10 - Line 4	(4,763)
13			
14	Revenue Conversion Factor	Exh. A-3, Sch. C2	<u>1.347</u>
15			
16	Revenue Deficiency (Sufficiency)	Line 12 x Line 14	<u><u>\$ (6,414)</u></u>

Schedule A-2

Line	[A] Description	[B]	[C]	[D] Calendar Year		[E]	[F]
		2019	2018	2017	2016		
1	Operating Revenue	\$ 144,530	\$ 148,416	\$ 138,566	\$ 127,107	\$ 138,300	
2	Operating Expense	(118,178)	(122,219)	(116,448)	(110,189)	(119,664)	
3	Pre-Tax Operating Income	26,352	26,197	22,118	16,918	18,636	
4	Income Taxes	(4,305)	(5,530)	(6,840)	(5,288)	(5,619)	
5	Net Operating Income	22,047	20,667	15,278	11,630	13,017	
6	Other Income and Deductions	(277)	(200)	332	(119)	(3)	
7	AFUDC	339	131	102	6	45	
8	Interest Charges	(3,814)	(3,857)	(4,179)	(3,685)	(4,329)	
9	Preferred Stock Dividends	-	-	-	-	-	
10	Net Income Available for Common	18,295	16,741	11,533	7,831	8,729	
11	Year End Average Unadjusted Common Equity	177,774	154,745	143,848	137,406	142,335	
12	Earned Rate of Return on Common Equity	10.29%	10.82%	8.02%	5.70%	6.13%	
13	Authorized Return on Common Equity	9.90%	9.90%	9.90%	9.90%	10.25%	

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Financial Metrics - Financial Basis
(\$000)

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	[A]	[B]	[C]	[D]	[E]	[F]
		Calendar Year				
Line	Description	2019	2018	2017	2016	2015
	<u>EBIT Interest Coverage Ratio</u>					
14	Pre-Tax Operating Income	\$ 26,352	\$ 26,197	\$ 22,118	\$ 16,918	\$ 18,636
15	Other Income and Deductions	(277)	(200)	332	(119)	(3)
16	AFUDC	339	131	102	6	45
17	Total EBIT	26,414	26,128	22,552	16,805	18,677
18	Interest Charges	3,814	3,857	4,179	3,685	4,329
19	EBIT Interest Coverage Ratio	6.93	6.77	5.40	4.56	4.31
	<u>EBITDA Interest Coverage Ratio</u>					
20	Total EBIT	\$ 26,414	\$ 26,128	\$ 22,552	\$ 16,805	\$ 18,677
21	Depreciation and Amortization	12,885	12,539	11,711	9,732	9,124
22	Total EBITDA	39,299	38,667	34,263	26,537	27,801
23	Interest Charges	3,814	3,857	4,179	3,685	4,329
24	EBITDA Interest Coverage Ratio	10.30	10.03	8.20	7.20	6.42
	<u>Funds Flow from Operations (FFO) Interest Coverage Ratio</u>					
25	Net Operating Income	\$ 22,047	\$ 20,667	\$ 15,278	\$ 11,630	\$ 13,017
26	Depreciation and Amortization	12,885	12,539	11,711	9,732	9,124
27	Deferred Income Tax	4,545	4,037	13,720	6,181	9,953
28	AFUDC	339	131	102	6	45
29	Other Major Recurring Non-Cash Items	1,583	425	(7,226)	6,172	(32)
30	Interest Paid	3,814	3,857	4,179	3,685	4,329
31	Less:					
32	Operating Lease Adjustment to Depreciation	-	-	-	-	-
33	Subtotal	45,213	41,655	37,763	37,406	36,437
34	Interest Charges	3,814	3,857	4,179	3,685	4,329
35	FFO Interest Coverage Ratio	11.85	10.80	9.04	10.15	8.42

Schedule A-2

	[A]	[B]	[C]	[D]	[E]	[F]
		Calendar Year				
Line	Description	2019	2018	2017	2016	2015
	<u>Overall Fixed Charge Coverage Ratio</u>					
36	Net Income Available for Common	\$ 18,295	\$ 16,741	\$ 11,533	\$ 7,831	\$ 8,729
37	Interest Charges	3,814	3,857	4,179	3,685	4,329
38	Subtotal Numerator	22,109	20,598	15,712	11,516	13,058
39	Interest Charges	3,814	3,857	4,179	3,685	4,329
40	Preferred Stock Dividends	-	-	-	-	-
41	Subtotal Denominator	3,814	3,857	4,179	3,685	4,329
42	Overall Fixed Charge Coverage Ratio	5.80	5.34	3.76	3.13	3.02
	<u>Cash Flow Coverage of Dividends Ratio</u>					
43	Net Income Available for Common	\$ 18,295	\$ 16,741	\$ 11,533	\$ 7,831	\$ 8,729
44	Depreciation and Amortization	12,885	12,539	11,711	9,732	9,124
45	Deferred Taxes	4,545	4,037	13,720	6,181	9,953
46	Subtotal	35,725	33,317	36,964	23,744	27,807
47	Common Dividends	-	-	-	-	-
48	Cash Flow Coverage of Dividend Ratio	N/A	N/A	N/A	N/A	N/A
	<u>Common Dividend Payout Ratio</u>					
49	Common Dividends	-	-	-	-	-
50	Net Income Available for Common	\$ 18,295	\$ 16,741	\$ 11,533	\$ 7,831	\$ 8,729
51	Common Dividend Payout Ratio	N/A	N/A	N/A	N/A	N/A
	<u>Permanent Capitalization</u>					
52	Long-term Debt	\$ 90,000	\$ 90,000	\$ 80,500	\$ 71,000	\$ 71,000
53	Preferred Stock	-	-	-	-	-
54	Common Equity	177,774	154,745	143,848	137,406	142,335
55	Total Permanent Capital	267,774	244,745	224,348	208,406	213,335
56	Long-term Debt Ratio	33.61%	36.77%	35.88%	34.07%	33.28%
57	Preferred Stock Ratio	-	-	-	-	-
58	Common Equity Ratio	66.39%	63.23%	64.12%	65.93%	66.72%
59	Total Permanent Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Financial Metrics - Financial Basis
(\$000)

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Line	[A] Description	[B] 2019	[C] 2018	[D] Calendar Year		[E] 2016	[F] 2015
				2017	2016		
60	Operating Revenue	\$ 144,530	\$ 148,416	\$ 138,566	\$ 127,107	\$ 138,300	
61	Operating Expense	(118,178)	(122,219)	(116,448)	(110,189)	(119,664)	
62	Pre-Tax Operating Income	26,352	26,197	22,118	16,918	18,636	
63	Income Taxes	(4,305)	(5,530)	(6,840)	(5,288)	(5,619)	
64	Net Operating Income	22,047	20,667	15,278	11,630	13,017	
65	Tax Impact of Pro-Forma Interest on NOI ¹	-	-	-	-	-	
66	AFUDC	339	131	102	6	45	
67	Interest Charges	(3,814)	(3,857)	(4,179)	(3,685)	(4,329)	
68	Preferred Stock Dividends	-	-	-	-	-	
69	Net Income Available for Common and JDITC	18,571	16,940	11,201	7,950	8,732	
70	Return Assignable to JDITC	-	-	-	-	-	
71	Net Income Available for Common	18,571	16,940	11,201	7,950	8,732	
72	13 mo. Average Adjusted Common Equity	134,757	119,255	103,116	93,830	90,668	
73	Earned Rate of Return on Common Equity	13.78%	14.21%	10.86%	8.47%	9.63%	
74	Authorized Return on Common Equity	9.90%	9.90%	9.90%	9.90%	10.25%	

Schedule A-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Financial Metrics - Financial Basis
(\$000)

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EBIT Interest Coverage Ratio

75	Pre-Tax Operating Income	\$	26,352	\$	26,197	\$	22,118	\$	16,918	\$	18,636
76	AFUDC		339		131		102		6		45
77	Total EBIT		26,690		26,328		22,220		16,924		18,680
78	Interest Charges		3,814		3,857		4,179		3,685		4,329
79	EBIT Interest Coverage Ratio		7.00		6.83		5.32		4.59		4.32

EBITDA Interest Coverage Ratio

80	Total EBIT	\$	26,690	\$	26,328	\$	22,220	\$	16,924	\$	18,680
81	Depreciation and Amortization		12,885		12,539		11,711		9,732		9,124
82	Total EBITDA		39,576		38,867		33,931		26,656		27,805
83	Interest Charges		3,814		3,857		4,179		3,685		4,329
84	EBITDA Interest Coverage Ratio		10.38		10.08		8.12		7.23		6.42

Funds Flow from Operations (FFO) Interest Coverage Ratio

85	Net Operating Income	\$	22,047	\$	20,667	\$	15,278	\$	11,630	\$	13,017
86	Depreciation and Amortization		12,885		12,539		11,711		9,732		9,124
87	Deferred Income Tax		4,545		4,037		13,720		6,181		9,953
88	AFUDC		339		131		102		6		45
89	Other Major Recurring Non-Cash Items		1,583		425		(7,226)		6,172		(32)
90	Interest Paid		3,814		3,857		4,179		3,685		4,329
91	Less:										
92	Operating Lease Adjustment to Depreciation		-		-		-		-		-
93	Subtotal		45,213		41,655		37,763		37,406		36,437
94	Interest Charges		3,814		3,857		4,179		3,685		4,329
95	FFO Interest Coverage Ratio		11.85		10.80		9.04		10.15		8.42

Overall Fixed Charge Coverage Ratio

96	Net Income Available for Common	\$	18,571	\$	16,940	\$	11,201	\$	7,950	\$	8,732
97	Interest Charges		3,814		3,857		4,179		3,685		4,329
98	Subtotal Numerator		22,385		20,797		15,380		11,635		13,061
99	Interest Charges		3,814		3,857		4,179		3,685		4,329
100	Preferred Stock Dividends		-		-		-		-		-
101	Subtotal Denominator		3,814		3,857		4,179		3,685		4,329
102	Overall Fixed Charge Coverage Ratio		5.87		5.39		3.68		3.16		3.02

Schedule A-2

	<u>Cash Flow Coverage of Dividends Ratio</u>										
103	Net Income Available for Common	\$	18,571	\$	16,940	\$	11,201	\$	7,950	\$	8,732
104	Depreciation and Amortization		12,885		12,539		11,711		9,732		9,124
105	Deferred Taxes		4,545		4,037		13,720		6,181		9,953
106	Subtotal		36,002		33,517		36,632		23,863		27,810
107	Common Dividends		-		-		-		-		-
108	Cash Flow Coverage of Dividend Ratio		N/A		N/A		N/A		N/A		N/A
	<u>Common Dividend Payout Ratio</u>										
109	Common Dividends		-		-		-		-		-
110	Net Income Available for Common	\$	18,571	\$	16,940	\$	11,201	\$	7,950	\$	8,732
111	Common Dividend Payout Ratio		N/A		N/A		N/A		N/A		N/A
	<u>Permanent Capitalization</u>										
112	Long-term Debt	\$	89,415	\$	89,370	\$	80,885	\$	71,000	\$	71,000
113	Preferred Stock		-		-		-		-		-
114	Common Equity		134,757		119,255		103,116		93,830		90,668
115	Total Permanent Capital		224,172		208,625		184,002		164,830		161,668
116	Long-term Debt Ratio		39.89%		42.84%		43.96%		43.07%		43.92%
117	Preferred Stock Ratio		-		-		-		-		-
118	Common Equity Ratio		60.11%		57.16%		56.04%		56.93%		56.08%
119	Total Permanent Capital		100.00%		100.00%		100.00%		100.00%		100.00%

¹ Data unavailable. Interest Charges on line 67 reflect total actual interest.

Schedule B-1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Rate Base
Historical 13 Month Average, December 31, 2019

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		(b)	(c)
Line No.	Description	Source	Rate Base (\$000)
1			
2	Plant in Service	Exh. A-2, Sch. B2	459,504
3	Plant Held for Future Use	Exh. A-2, Sch. B2	-
4	Construction Work in Progress	Exh. A-2, Sch. B2	17,445
5	Total Utility Plant	Sum Lines 2-4	476,949
6			
7	Less: Depreciation Reserve	Exh. A-2, Sch. B3	213,883
8			
9	Net Utility Plant	Line 5 - Line 7	263,066
10			
11	Net Capital Lease Property		0
12			
13	Total Utility Property and Plant	Line 9 + Line 11	263,066
14			
15	Less: Capital Lease Obligations		0
16			
17	Net Plant	Line 13 - Line 15	263,066
18			
19	Allowance for Working Capital	Exh. A-2, Sch. B4	42,886
20			
21	Total Rate Base	Line 17 + Line 19	\$ 305,953

Schedule B-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Total Utility Plant
Historical 13 Month Average, December 31, 2019

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(a)		(b)		
Line No.	Description	MPSC Account No.	Source	Utility Plant (\$000)
1				
2	Plant in Service	101	Workpapers 2019 Page 1	\$ 456,371
3	Plant purchased or sold	102		
4	Experimental plant unclassified	103		
5	Plant leased to others	104		
6	Completed construction not classified	106		
7	Gas Stored Base Gas	117	Workpapers 2019 Page 1	\$ 3,133
8	Plant in Service			\$ 459,504
9				
10	Plant held for future use	105		
11				
12	Construction work in progress	107	Workpapers 2019 Page 1	\$ 17,445
13				
14	Total Utility Plant			\$ 476,949

Schedule B-3

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Depreciation Reserve and Other Deductions
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-2
Schedule: B3
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Accumulated Provision for Depreciation (\$000)
1			
2	Accumulated Provision for Depreciation	Workpapers 2019 Page 1	\$ 213,883

Schedule B-4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Working Capital
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-2
Schedule: B4
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Working Capital (\$000)
1		Workpapers 2019 Page 3-4	
2	<u>Assets</u>		
3	Utility Plant-ARO		1,254
4	Accumulated Depreciation-ARO		(680)
5	Other Investment and Special Funds		100
6	Cash & Cash Equivalents		441
7	Temporary Cash Investments		-
8	Net Accounts Receivable		18,700
9	Prepayments		548
10	Accrued Utility Revenues		7,455
11	Fuel Stock/Gas Storage		11,307
12	Other Materials & Supplies		955
13	Derivative Assets		129
14	Other Current Assets		3,612
15	Prepaid Pension Expense		2,808
16	Other		6,882
17	Other Regulatory Assets		55,403
18			
19	Total Assets		<u>\$ 108,913</u>
20			
21	<u>Liabilities</u>		
22	Accounts Payable		15,624
23	Accrued Payroll, Vacation, & Interest		2,756
24	Accrued Taxes		4,618
25	Miscellaneous Current and Accrued Liabilities		8,138
26	Asset Retirement Obligation		2,154
27	Total Post Retirement OPEB and Pension Liability		1,405
28	Other Deferred Credits		23,001
29	Other Regulatory Liabilities		8,331
30			
31	Total Liabilities		<u>\$ 66,026</u>
32			
33	Total Working Capital		<u><u>\$ 42,886</u></u>

Schedule C-1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule: C1
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Net Operating Income (\$000)
1			
2	Operating Revenues	Exh. A-3, Sch. C3	\$ 144,530
3			
4	<u>Operating Expenses</u>		
5	Cost of Gas	Exh. A-3, Sch. C4	65,042
6	Operations and Maintenance Expenses	Exh. A-3, Sch. C5	32,942
7	Depreciation and Amortization	Exh. A-3, Sch. C6	12,885
8	General Taxes	Exh. A-3, Sch. C7	6,845
9	Income Taxes	Exh. A-3, Sch. C8 & C9	4,305
10	Total Operating Expenses		<u>\$ 122,020</u>
11			
12	Operating Income		\$ 22,510
13			
14	<u>Operating Income Adjustments</u>		
15	Allowance For Funds Used During Construction	Exh. A-3, Sch. C11	(339)
16	Loss on Reacquired Securities		
17	Income Tax Effect of Interest		
18	Interest Synchronization Adjustment		
19	Total Operating Income Adjustments		<u>\$ (339)</u>
20			
21	Adjusted Net Operating Income		<u><u>\$ 22,171</u></u>

Schedule C-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Revenue Conversion Factor

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C2
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Calc. Logic/Source	Amount
1			
2	Income Before Income Taxes		100.00%
3			
4	Michigan Corporate Income Tax Rate		6.00%
5			
6	Federal Income Tax Base	Ln 2 - Ln 4	94.00%
7			
8	Times Federal Income Tax Rate		21.00%
9			
10	Federal Income Tax	Ln 6 x Ln 8	19.74%
11			
12	Income After Taxes	Ln 6 - Ln 10	74.26%
13			
14	Gross Revenue Conversion Factor	Ln 2 / Ln 12	1.3466

Schedule C-3

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Operating Revenue
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C3
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line

No.	Description	Source	Sales Revenue (\$000)
1			
2	Sales Revenue	MPSC Report, p. 300	\$ 141,019
3			
4	Energy Optimization Revenue		\$ 0
5			
6	Other Revenues	MPSC Report, p. 300	\$ 3,511
7			
8	Total Revenue		<u>\$ 144,530</u>

Schedule C-4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Gas Sold
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C4
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line No.	Description	Source	Cost of Gas (\$000)
1			
2	Cost of Gas:		
3	Energy	Workpapers 2019 Page 5	\$ 65,042
4	Dem-Peak Day (D-1)		-
5	Other COG		-
6			
7	Total Cost of Gas		<u>\$ 65,042</u>

Schedule C5

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Operation and Maintenance Expenses
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C5
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Operation and Maintenance Expenses (\$000)
1			
2	Production - Other:		
3	Energy		-
4	Dem-Peak Day (D-1)		-
5	Other Production		-
6	Manufactured Gas Production	MPSC Report, p. 320	888
7	Gas Supply	Workpapers 2019 Page 5	380
8	Other COG		-
9			
10	Total Production-Other		<u>\$ 1,267</u>
11			
12	Operation and Maintenance Expenses:		
13	Storage	MPSC Report, p. 322	463
14	Transmission	MPSC Report, p. 324	478
15	Distribution	MPSC Report, p. 324	8,674
16	Customer Accounts	MPSC Report, p. 325	8,562
17	Sales	MPSC Report, p. 325	2
18	Customer Service	MPSC Report, p. 325	3,469
19	Administration & General	MPSC Report, p. 325	10,489
20			
21	Total Operation and Maintenance Expenses		<u>\$ 31,675</u>
22			
23	Total Production-Other and Operation & Maintenance Expenses		<u><u>\$ 32,942</u></u>

Schedule C-6

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Depreciation and Amortization Expenses
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C6
Page: 1 of 1
Witness: Joe Zgonc

(a)			(b)		(c)	
Line No.	Description	Source	Depreciation & Amortization Expense (\$000)			
1						
2	Depreciation and Amortization Expense					
3	Depreciation and Amortization Expense	MPSC Report, p. 337	\$		12,885	
4						
5						
6	Total Depreciation and Amortization Expense		\$		12,885	

Schedule C-7

Michigan Public Service Commission
Michigan Gas Utilities Corporation
General Taxes
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C7
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Source	General Taxes (\$000)
1			
2	FEDERAL		
3	Payroll Taxes	Workpapers 2019 Page 6	\$ 1,003
4	Unemployment Comp	Workpapers 2019 Page 6	10
5	PR Taxes Credited	Workpapers 2019 Page 6	(57)
6	Super Fund Tax		
7	Highway Use Tax		
8	Federal Excise Tax		
9			
10	STATE		
11	Gross Receipts Tax		
12	Unemployment Comp	Workpapers 2019 Page 6	46
13	Remain. Assessment		
14	Use Tax		
15	Unauthor Ins Tax		
16	Wis Recycling Fee		
17	Single Business Tax		
18	Property		
19			
20	LOCAL		
21	Real Est & Property	Workpapers 2019 Page 6	\$ 5,810
22			
23	WBS		
24	WBS Payroll Tax	Workpapers 2019 Page 6	\$ 34
25			
26	OTHER		
27	Franchise Tax Fees		\$ -
28	State Unitary Fees		-
29			
30	Total General Taxes		<u>\$ 6,845</u>

Schedule C-8

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Federal Income Taxes
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C8
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Source	Federal Income Taxes (\$000)
1			
2	Federal Income Taxes	Workpapers 2019 Page 7	\$ 2,819

Schedule C-9

Michigan Public Service Commission
Michigan Gas Utilities Corporation
State Income Taxes
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C9
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Source	State Income Taxes (\$000)
1			
2	State Income Taxes	Workpapers 2019 Page 7	\$ 1,486

Schedule C10

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Other (or Local) Taxes
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C10
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line

No.	Description	Source	Other (or Local) Taxes
1			
2	All Taxes Other than Income are included on Exhibit A-3, Schedule C-7		

Schedule C11

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Allowance for Funds Used During Construction
For the Historical Year Ended December 31, 2019

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C11
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Source	AFUDC (\$000)
1			
2	AFUDC Debt	MPSC Report, p. 117	\$ (109)
3	AFUDC Equity	MPSC Report, p. 117	\$ (229)
4			
5	Total AFUDC		<u>\$ (339)</u>

Schedule D-1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Rate of Return Summary
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-4
Schedule: D1
Page: 1 of 1
Witness: Joe Zgonc

Line	(a) Description	(b) (c) (d) Capital Structure			(e) Cost Rate %	(f) (g) (h) (i) Weighted Cost			
		(b) Amount (\$000) (1)	(c) Percent Permanent Capital (2)	(d) Percent of Total Capital		(f) Permanent Capital (2)	(g) Total Cost %	(h) Conversion Factor	(i) Pre-Tax Return
1									
2	Long-Term Debt	\$ 89,413	39.89%	29.22%	3.58% (3)	1.43%	1.05%		1.05%
3									
4	Preferred Stock	\$ -	0.00%	0.00%	0.00% (4)	0.00%	0.00%		0.00%
5									
6	Common Shareholders' Equity	\$ 134,757	60.11%	44.05%	9.90% (5)	5.95%	4.36%	1.347	5.87%
7									
8	Total Permanent Capital	\$ 224,171	100.00%			7.38%			
9									
10	Short-Term Debt	\$ 28,702		9.38%	3.01% (6)		0.28%		0.28%
11									
12	Job Development - ITC - Debt								
13	Job Development - ITC Equity								
14	Total Job Development - ITC	\$ -		0.00%	7.38%				
15									
16	Deferred Income Taxes (Net) - Federal	\$ 59,237		19.36%	0.00%		0.00%		0.00%
17									
18	Deferred Tax Proration	\$ 0		0.00%	6.88%		0.00%		0.00%
19									
20	Capital Structure Adjustments	\$ (6,157)		-2.01%	0.00%		0.00%		0.00%
21									
22	Total	\$ 305,953		100.00%			5.69%		7.20%

- (1) See Exh. A-2, Sch. B1
- (2) Excludes Short-Term Debt, Deferred Job Development Investment Tax Credit, Deferred Investment Tax Credit and Deferred Income Taxes to calculate the rate of return for Job Development Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6
- (3) See Exh. A-4, Sch. D2
- (4) See Exh. A-4, Sch. D4
- (5) See Exh. A-4, Sch. D5
- (6) See Exh. A-4, Sch. D3

Schedule D-2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Long-Term Debt
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-4
Schedule: D2
Page: 1 of 1
Witness: Joe Zgonc

[illegible]

Schedule D-3

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Short-Term Debt
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-4
Schedule: D3
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line No.	Month	Balance Outstanding (\$000)	Total Cost (\$000)
1			
2	Inter-Company Loans		
3	Dec	\$ 22,925	
4	Jan	41,400	\$ 62
5	Feb	39,825	\$ 82
6	Mar	31,750	\$ 79
7	Apr	26,450	\$ 60
8	May	22,025	\$ 51
9	Jun	26,950	\$ 50
10	Jul	31,500	\$ 62
11	Aug	36,900	\$ 70
12	Sep	21,300	\$ 70
13	Oct	20,900	\$ 40
14	Nov	23,600	\$ 34
15	Dec	27,600	\$ 37
16	13 month Average/Total	<u>\$ 28,702</u>	<u>\$ 697</u>
17			
18	Credit Facility Fees and Amortization	-	137
19			
20	Guarantee Fees	-	30
21			
22	Other	-	-
23			
24	Total	<u>\$ 28,702</u>	<u>\$ 863</u>
25			
26	Average Cost of Short-Term Debt		<u>3.01%</u>

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Preferred Stock
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-4
Schedule: D4
Page: 1 of 1
Witness: Joe Zgonc

[illegible]

Schedule D-5

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Common Shareholders' Equity
Historical 13 Month Average, December 31, 2019

Case No.: U-20718
Exhibit No.: A-4
Schedule: D5
Page: 1 of 1
Witness: Joe Zgonc

Line No.		Adjusted Common Stock (\$000)
1		
2	Dec	127,174
3	Jan	117,860
4	Feb	121,728
5	Mar	125,541
6	Apr	126,860
7	May	127,720
8	Jun	127,429
9	Jul	127,947
10	Aug	127,501
11	Sep	152,364
12	Oct	153,622
13	Nov	156,757
14	Dec	159,343
15		
16	Average	<u>\$134,757</u> <u>9.90% (1)</u>

(1) Historical ROE is per order in Docket U-17880

Schedule E1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Annual Service Area Sales by Major Customer Classes and System Output
5-Year Historical
Units in MMcf

Case No.: U-20718
Exhibit No.: A-5
Schedule: E1
Page: 1 of 1
Witness: Jared J. Peccarelli

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line									
No.	<u>Year</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>Other</u>	<u>Total</u>	<u>Losses and CU</u>	<u>% of Output</u>	<u>System Output</u>
1	2016	12,706	6,412	11,829	-	30,947	555	1.8%	31,501
2	2017	12,494	6,382	12,085	-	30,961	388	1.3%	31,349
3	2018	14,768	7,267	12,648	-	34,683	(529)	-1.5%	34,155
4	2019	14,957	7,383	12,765	-	35,104	(323)	-0.9%	34,781
5	2020	12,798	6,236	12,464	-	31,498	(264)	-0.8%	31,234

Note: EUT volumes added to Industrial class.

Schedule A-1

Michigan Public Service Commission
Michigan Gas Utilities
Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-11
Schedule: A1
Page: 1 of 1
Witness: Joe Zgonc

Line No.	(a) Description	(b) Source	(c) Total (\$000)
1			
2	Rate Base	Exh. A-12, Sch. B1	\$ 400,888
3			
4	Adjusted Net Operating Income	Exh. A-13, Sch. C1	11,705
5			
6	Overall Rate of Return	Line 4 ÷ Line 2	2.92%
7			
8	Required Rate of Return	Exh. A-14, Sch. D1	5.72%
9			
10	Income Requirements	Line 2 x Line 8	22,939
11			
12	Income Deficiency (Sufficiency)	Line 10 - Line 4	11,234
13			
14	Revenue Conversion Factor	Exh. A-13, Sch. C2	1.347
15			
16	Revenue Deficiency (Sufficiency)	Line 12 x Line 14	\$ 15,128

Line No.	[A] Description	[B] Projected 2022 No Rate Relief	[C] Projected 2022 Full Rate Relief
1	Operating Revenue	\$ 142,160	\$ 157,288
2	Operating Expense	(129,478)	(129,478)
3	Pre-Tax Operating Income	12,683	27,810
4	Income Taxes	(978)	(4,871)
5	Net Operating Income	11,704	22,939
6	Tax Impact of Pro-Forma Interest on NOI	-	-
7	AFUDC	-	-
8	Interest Charges	(5,426)	(5,431)
9	Preferred Stock Dividends	-	-
10	Net Income Available for Common and JDITC	6,278	17,508
11	Return Assignable to JDITC	-	-
12	Net Income Available for Common	6,278	17,508
13	Average Common Equity	171,644	171,644
14	Earned Rate of Return on Common Equity	3.66%	10.20%
15	Authorized / Requested Return on Common Equity	9.90%	10.20%

Line No.	[A] Description	[B] Projected 2022 No Rate Relief	[C] Projected 2022 Full Rate Relief
	<u>EBIT Interest Coverage Ratio</u>		
16	Pre-Tax Operating Income	\$ 12,683	\$ 27,810
17	AFUDC	-	-
18	Total EBIT	12,683	27,810
19	Interest Charges	5,426	5,431
20	EBIT Interest Coverage Ratio	2.3	5.1
	<u>EBITDA Interest Coverage Ratio</u>		
21	Total EBIT	\$ 12,683	\$ 27,810
22	Depreciation and Amortization	19,225	19,225
23	Total EBITDA	31,908	47,035
24	Interest Charges	5,426	5,431
25	EBITDA Interest Coverage Ratio	5.9	8.7
	<u>Funds Flow from Operations (FFO) Interest Coverage Ratio</u>		
26	Net Operating Income	\$ 6,278	\$ 17,508
27	Depreciation and Amortization	19,225	19,225
28	Deferred Income Tax	3,721	3,721
29	AFUDC	-	-
30	Other Major Recurring Non-Cash Items	-	-
31	Interest Paid	5,426	5,431
32	Less: Operating Lease Adjustment to Depreciation	-	-
33	Subtotal	34,650	45,885
34	Interest Charges	5,426	5,431
35	FFO Interest Coverage Ratio	6.4	8.4
	<u>Overall Fixed Charge Coverage Ratio</u>		
36	Net Income Available for Common	\$ 6,278	\$ 17,508
37	Interest Charges	5,426	5,431
38	Subtotal Numerator	11,704	22,939
39	Interest Charges	5,426	5,431
40	Preferred Stock Dividends	-	-
41	Subtotal Denominator	5,426	5,431
42	Overall Fixed Charge Coverage Ratio	2.2	4.2

Line No.	[A] Description	[B] Projected 2022 No Rate Relief	[C] Projected 2022 Full Rate Relief
	<u>Cash Flow Coverage of Dividends Ratio</u>		
43	Net Income Available for Common	\$ 6,278	\$ 17,508
44	Depreciation and Amortization	19,225	19,225
45	Deferred Taxes	3,721	3,721
46	Subtotal	29,224	40,454
47	Common Dividends	-	7,294
48	Cash Flow Coverage of Dividend Ratio	N/A	5.5
	<u>Common Dividend Payout Ratio</u>		
49	Common Dividends	\$ -	\$ 7,294
50	Net Income Available for Common	6,278	17,508
51	Common Dividend Payout Ratio	N/A	41.7%
	<u>Permanent Capitalization</u>		
52	Long-term Debt	\$ 155,297	\$ 155,297
53	Preferred Stock	-	-
54	Common Equity	171,644	171,644
55	Total Permanent Capital	326,940	326,940
56	Long-term Debt Ratio	47.5%	47.5%
57	Preferred Stock Ratio	0.0%	0.0%
58	Common Equity Ratio	52.5%	52.5%
59	Total Permanent Capital	100.0%	100.0%

Schedule B-1

Michigan Public Service Commission
Michigan Gas Utilities
Projected Rate Base
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-12
Schedule: B1
Page: 1 of 1
Witness: Joe Zgonc

		(b)	(c)
Line No.	Description	Source	Rate Base (\$000)
1			
2	Plant in Service	Exh. A-12, Sch. B2	614,692
3	Plant Held for Future Use	Exh. A-12, Sch. B2	-
4	Construction Work in Progress	Exh. A-12, Sch. B2	6,779
5	Total Utility Plant	Sum Lines 2-4	621,471
6			
7	Less: Depreciation Reserve	Exh. A-12, Sch. B3	254,172
8			
9	Net Utility Plant	Line 5 - Line 7	367,298
10			
11	Net Capital Lease Property		0
12			
13	Total Utility Property and Plant	Line 9 + Line 11	367,298
14			
15	Less: Capital Lease Obligations		0
16			
17	Net Plant	Line 13 - Line 15	367,298
18			
19	Allowance for Working Capital	Exh. A-12, Sch. B4	33,590
20			
21	Total Projected Test Period Rate Base	Line 17 + Line 19	\$ 400,888

Schedule B-2

Michigan Public Service Commission
Michigan Gas Utilities
Total Utility Plant
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-12
Schedule: B2
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)		
Line No.	Description	MPSC Account No.	Source	Projected Utility Plant (\$000)
1				
2	Plant in Service	101		\$ 611,559
3	Plant purchased or sold	102		
4	Experimental plant unclassified	103		
5	Plant leased to others	104		
6	Completed construction not classified	106		
7	Gas Stored Base Gas	117		\$ 3,133
8	Plant in Service		Workpapers 2022 Page 1	\$ 614,692
9				
10	Plant held for future use	105		
11				
12	Construction work in progress	107	Workpapers 2022 Page 1	\$ 6,779
13				
14	Total Projected Period Utility Plant			<u>\$ 621,471</u>

Schedule B-3

Michigan Public Service Commission
Michigan Gas Utilities
Depreciation Reserve and Other Deductions
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-12
Schedule: B3
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Projected Accumulated Provision for Depreciation (\$000)
1			
2	Projected Accumulated Provision for Depreciation	Workpapers 2022 Page 1	\$ 254,172

Schedule B-4

Michigan Public Service Commission
Michigan Gas Utilities
Working Capital
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-12
Schedule: B4
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Projected Working Capital (\$000)
1		Workpapers 2022 Page 2-3	
2	<u>Assets</u>		
3	Utility Plant-ARO		1,254
4	Accumulated Depreciation-ARO		(753)
5	Other Investment and Special Funds		100
6	Cash & Cash Equivalents		1,968
7	Net Accounts Receivable		16,418
8	Prepayments		53
9	Accrued Utility Revenues		10,148
10	Fuel Stock/Gas Storage		7,425
11	Other Materials & Supplies		1,149
12	Derivative Assets		967
13	Other Current Assets		1,010
14	Prepaid Pension Expense		7,001
15	Other		1,761
16	Other Regulatory Assets		50,725
17			
18	Total Assets		<u>\$ 99,225</u>
19			
20	<u>Liabilities</u>		
21	Accounts Payable		19,354
22	Accrued Payroll, Vacation, Taxes, & Interest		3,458
23	Accrued Taxes		3,071
24	Miscellaneous Current and Accrued Liabilities		8,134
25	Asset Retirement Obligation		2,212
26	Total Post Retirement OPEB and Pension Liability		1,947
27	Other Deferred Credits		20,402
28	Other Regulatory Liabilities		7,058
29			
30	Total Liabilities		<u>\$ 65,636</u>
31			
32	Total Projected Working Capital		<u><u>\$ 33,590</u></u>

Schedule B-5

Michigan Public Service Commission
Michigan Gas Utilities
Summary of Actual and Projected Gas Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Capital Expenditures									
Line No.	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year	Reference	Last Rate Case Approved Spending Plan U-17880 12 mos. Ended 12/31/2016 ¹	Actual Spending Test Year U-17880 12 mos. Ended 12/31/2016 ¹
				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021	12 mos. Ending 12/31/2022			
1						col. (d) + (e)				
2	Underground Gas Storage	3,059	2,275	596	1,942	2,539	3,995	Exh. A-12, Sch B5.1	xxxxx	xxxxx
3	Transmission	5,407	1,012	1,887	3,703	5,591	17,581	Exh. A-12, Sch B5.2	xxxxx	xxxxx
4	Distribution Plant	26,696	31,493	12,651	31,172	43,823	27,405	Exh. A-12, Sch B5.3	xxxxx	xxxxx
5	General	2,106	4,870	2,101	2,494	4,595	2,002	Exh. A-12, Sch B5.4	xxxxx	xxxxx
6	Intangible	3,128	5,919	1,623	3,065	4,688	6,441	Exh. A-12, Sch B5.5	xxxxx	xxxxx
7	Total Capital Expenditures	\$ 40,397	\$ 45,569	\$ 18,858	\$ 42,377	\$ 61,235	\$ 57,425		\$ -	\$ -

¹ Note: The order issued for Case No. U-17880 approved a black box settlement agreement. The approved capital spending identified in the settlement agreement is unknown and inaccessible.

Schedule B-5.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Underground Gas Storage Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5.1
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year
				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021	12 mos. Ending 12/31/2022
						col. (d) + (e)	
1	<u>Gas Storage</u>						
2	MGU Gas MI 351, Natural Gas Underground Storage Structures and improvements	811	1,586	185	510	695	400
3	MGU Gas MI 352.4, Nat Gas Storage and Processing Plant - Wells-Wells	1,535	346	325	547	872	697
4	MGU Gas MI 353.2, Nat Underground Gas Storage Lines	-	-	0	100	100	175
5	MGU Gas MI 354.2, NatGas Underground Storage Compressor station equipment	335	219	16	340	356	2,502
6	MGU Gas MI 355.2, Nat Underground Gas Storage Measuring and regulating Equip	1	94	20	445	465	120
7	MGU Gas MI 356.2, Nat Underground Gas Storage Purification equip.	374	30	-	-	-	100
8	MGU Gas MI 357.1, Natl Underground Gas Storage Other equip.	4	-	50	-	50	-
9	Total Gas Storage Capital Expenditures	3,059	2,275	596	1,942	2,539	3,995

Schedule B-5.2

Michigan Public Service Commission
Michigan Gas Utilities
Transmission Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5.2
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year
				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021 <i>col. (d) + (e)</i>	12 mos. Ending 12/31/2022
1	<u>Transmission</u>						
2	MGU Gas MI 366.1, Gas Transmission Structures and improvements	26	5	-	-	-	-
3	MGU Gas MI 367.1, Gas Transmission Mains	1,311	246	1,542	3,203	4,745	17,066
4	MGU Gas MI 369.3, Gas Transmission Measuring & regulating equipment	4,070	761	345	500	846	515
5	Total Transmission Capital Expenditures	5,407	1,012	1,887	3,703	5,591	17,581

Schedule B-5.3

Michigan Public Service Commission
Michigan Gas Utilities
Distribution Plant Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5.3
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year
				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021 <i>col. (d) + (e)</i>	12 mos. Ending 12/31/2022
1	<u>Distribution</u>						
2	MGU Gas MI 376.1, Gas Distribution Mains-Gas Mains-Steel	6,214	3,736	4,174	4,038	8,212	2,480
3	MGU Gas MI 376.2, Gas Distribution Mains-Gas Mains-Plastic	5,951	4,673	2,182	11,176	13,358	11,396
4	MGU Gas MI 378, Gas Distribution Measuring & Reg equipment	2,893	954	157	1,001	1,158	1,031
5	MGU Gas MI 379, Gas Distribution City Gate Stations	179	21	-	-	-	-
6	MGU Gas MI 380.1, Gas Distribution Services-Gas Services-Steel	213	220	406	(602)	(196)	(756)
7	MGU Gas MI 380.2, Gas Distribution Services-Gas Services-Plastic	7,700	3,964	1,213	8,765	9,978	9,031
8	MGU Gas MI 381, Gas Distribution Meters	3,114	2,008	1,182	4,003	5,185	4,124
9	MGU Gas MI 381.2, Gas Distribution Meters-AMR Devices	-	15,698	3,336	2,791	6,127	100
10	MGU Gas MI 383, Gas Distribution House regulators	408	187	-	-	-	-
11	MGU Gas MI 385, Gas Distribution Industrial meas & regulating equip	23	33	-	-	-	-
12	Total Distribution Plant Capital Expenditures	26,696	31,493	12,651	31,172	43,823	27,405

Schedule B-5.5

Michigan Public Service Commission
Michigan Gas Utilities
General Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5.4
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year
				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021 <i>col. (d) + (e)</i>	12 mos. Ending 12/31/2022
1	<u>General</u>						
2	MGU Gas MI 390, Gas General Structures and improvements	40	3	766	526	1,293	641
3	MGU Gas MI 391.1 Office Furniture and Equip	4	9	-	-	-	-
4	MGU Gas MI 391.2 Computer Equipment	446	82	223	493	716	430
5	MGU Gas MI 391.2 Server/Network Equipment	296	166	60	222	281	298
6	MGU Gas MI 392.1, Gas General Transportation equipment-Trans Equip	530	72	240	638	878	525
7	MGU Gas MI 392.2, Gas General Transportation Equipment-Trailers	34	-	-	-	-	-
8	MGU Gas MI 392.2, Gas General Transportation Equipment-Trailers Wheel Mounted Pw	64	-	-	-	-	-
9	MGU Gas MI 394, Gas General Tools, shop and garage equipment	677	129	39	105	144	107
10	MGU Gas MI 396, Gas General Power operated equipment	13	-	-	-	-	-
11	MGU Gas MI 397.1, Gas General Communication equipment-Comm Equip	3	4,409	773	510	1,283	-
12	Total General Capital Expenditures	2,106	4,870	2,101	2,494	4,595	2,002

Schedule B-5.5

Michigan Public Service Commission
Michigan Gas Utilities
Intangible Capital Expenditures
for the years 2019 through December 2022
(\$000)

Case No.: U-20718
Exhibit No.: A-12
Schedule: B5.5
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line	Description	Historical 12 mos. ended 12/31/2019	Histoical 9 mos. Ended 9/30/2020	Projected Bridge Year			Projected Test Year
No.				3 mos. Ending 12/31/2020	12 mos. Ending 12/31/2021	15 mos. Ending 12/31/2021 <i>col. (d) + (e)</i>	12 mos. Ending 12/31/2022
1	<u>Intangible</u>						
2	MGU Gas MI Software 303 (ERP) - 10 year	3	-	-	-	-	-
3	MGU Gas MI Software 303 (ERP) - 15 year	443	44	-	-	-	-
4	MGU Gas MI Software 303 (ERP) - 5 year	64	7	-	-	-	-
5	MGU Gas MI Software 303 - 10 year	1,003	4,745	901	1,381	2,282	3,094
6	MGU Gas MI Software 303 - 15 year	115	482	466	895	1,361	2,692
7	MGU Gas MI Software 303 - 5 year	1,264	641	247	788	1,035	656
8	MGU Gas MI Software 303 - 7 year	235	0	10	-	10	-

Schedule C-1

Michigan Public Service Commission
Michigan Gas Utilities
Adjusted Net Operating Income
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule: C1
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

Line No.	Description	Source	Net Operating Income (\$000)
1			
2	Operating Revenues	Exh. A-13, Sch. C3	\$ 142,160
3			
4	<u>Operating Expenses</u>		
5	Cost of Gas	Exh. A-13, Sch. C4	65,314
6	Operations and Maintenance Expenses	Exh. A-13, Sch. C5	34,964
7	Depreciation and Amortization	Exh. A-13, Sch. C6	19,225
8	Regulatory Items, Debits and Credits		2,500
9	General Taxes	Exh. A-13, Sch. C7	7,475
10	Income Taxes	Exh. A-13, Sch. C8 & C9	977
11	Total Operating Expenses		<u>\$ 130,455</u>
12			
13	Operating Income		\$ 11,705
14			
15	<u>Operating Income Adjustments</u>		
16	Allowance For Funds Used During Construction	Exh. A-13, Sch. C11	-
17	Loss on Reacquired Securities		
18	Income Tax Effect of Interest		
19	Interest Synchronization Adjustment		
20	Total Operating Income Adjustments		<u>\$ -</u>
21			
22	Adjusted Net Operating Income		<u><u>\$ 11,705</u></u>

Schedule C-2

Michigan Public Service Commission
Michigan Gas Utilities
Projected Revenue Conversion Factor

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C2
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)
Line No.	Description	Calc. Logic/Source	Amount
1			
2	Income Before Income Taxes		100.00%
3			
4	Michigan Corporate Income Tax Rate		6.00%
5			
6	Federal Income Tax Base	Ln 2 - Ln 4	94.00%
7			
8	Times Federal Income Tax Rate		21.00%
9			
10	Federal Income Tax	Ln 6 x Ln 8	19.74%
11			
12	Income After Taxes	Ln 6 - Ln 10	74.26%
13			
14	Gross Revenue Conversion Factor	Ln 2 / Ln 12	1.347

Schedule C-3

Michigan Public Service Commission
Michigan Gas Utilities
Projected Operating Revenue
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C3
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line

No.	Description	Source	Projected Sales Revenue (\$000)
1			
2	Sales Revenue	Workpapers 2022 Page 4	\$ 141,029
3			
4	Energy Optimization Revenue		\$ 0
5			
6	Other Revenues	Workpapers 2022 Page 4	\$ 1,131
7			
8	Total Revenue		<u>\$ 142,160</u>

Schedule C-4

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Gas Sold
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C4
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line No.	Description	Source	Cost of Gas (\$000)
1			
2	Cost of Gas:		
3	Energy	Workpapers 2022 Page 4	\$ 65,314
4	Dem-Peak Day (D-1)		-
5	Other COG		-
6			
7	Total Cost of Gas		<u>\$ 65,314</u>

Schedule C5

Michigan Public Service Commission
Michigan Gas Utilities
Projected Operation and Maintenance Expenses
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-3
Schedule No.: C5
Page: 1 of 1
Witness: Joe Zgonc

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	Source	Historical Operation and Maintenance Expenses (\$000)	Change in Operation and Maintenance Expenses (\$000)	Projected 2022 Operation and Maintenance Expenses (\$000)
1					
2	Production - Other:				
3	Energy				-
4	Dem-Peak Day (D-1)				-
5	Other Production				-
6	Manufactured Gas Production	Zgonc Exhibit 1, Line 29	888	94	981
7	Gas Supply	Zgonc Exhibit 1, Line 66	380	32	412
8	Other COG				-
9					
10	Total Production-Other		\$ 1,267	\$ 126	\$ 1,393
11					
12	Operation and Maintenance Expenses:				
13	Storage	Zgonc Exhibit 1, Line 100	463	115	578
14	Transmission	Zgonc Exhibit 1, Line 119	478	279	757
15	Distribution	Zgonc Exhibit 1, Line 145	8,675	2,731	11,406
16	Customer Accounts	Zgonc Exhibit 1, Line 154	8,562	(602)	7,960
17	Customer Service	Zgonc Exhibit 1, Line 162	579	46	625
18	Sales	Zgonc Exhibit 1, Line 170	2	0	2
19	Administration & General	Zgonc Exhibit 1, Line 193	10,911	1,333	12,244
20					
21	Total Operation and Maintenance Expenses		\$ 29,670	\$ 3,901	\$ 33,571
22					
23	Total Production-Other and Operation & Maintenance Expenses		\$ 30,937	\$ 4,027	\$ 34,964

Schedule C-6

Michigan Public Service Commission
Michigan Gas Utilities
Projected Depreciation and Amortization Expenses
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C6
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line No.	Description	Source	Projected Depreciation & Amortization Expense (\$000)
1			
2	Depreciation and Amortization Expense		
3	Depreciation Expense	Workpapers 2022 Page 5	\$ 19,225
4	Amortization Expense		-
5			
6	Total Depreciation and Amortization Expense		<u>\$ 19,225</u>

Schedule C-7

Michigan Public Service Commission
Michigan Gas Utilities
Projected General Taxes
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C7
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line No.	Description	Source	Projected General Taxes (\$000)
1			
2	FEDERAL		
3	Payroll Taxes	Workpapers 2022 Page 6	\$ 1,124
4	Unemployment Comp		-
5	PR Taxes Credited		-
6	Super Fund Tax		-
7	Highway Use Tax		-
8	Federal Excise Tax		-
9			
10	STATE		
11	Gross Receipts Tax		\$ -
12	Unemployment Comp		-
13	Remain. Assessment		-
14	Use Tax		-
15	Unauthor Ins Tax	Workpapers 2022 Page 6	\$ 19
16	Wis Recycling Fee		-
17	Single Business Tax		-
18	Property	Workpapers 2022 Page 6	\$ 6,332
19			
20	LOCAL		
21	Real Est & Property		\$ -
22			
23	WBS		
24	WBS Payroll Tax		\$ -
25			
26	OTHER		
27	Franchise Tax Fees		\$ -
28	State Unitary Fees		-
29			
30	Total General Taxes		<u>\$ 7,475</u>

Schedule C-8

Michigan Public Service Commission
Michigan Gas Utilities
Projected Federal Income Taxes
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C8
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)	
Line No.	Description	Source	Projected Federal Income Taxes (\$000)	
1				
2	Federal Income Taxes	Workpapers 2022 Page 7	\$	810

Schedule C-9

Michigan Public Service Commission
Michigan Gas Utilities
Projected State Income Taxes
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C9
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line No.	Description	Source	Projected State Income Taxes (\$000)
1			
2	State Income Taxes	Workpapers 2022 Page 7	\$ 167

Schedule C10

Michigan Public Service Commission
Michigan Gas Utilities
Other (or Local) Taxes
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C10
Page: 1 of 1
Witness: Joe Zgonc

(a)

(b)

(c)

Line

No.	Description	Source	Projected Other (or Local) Taxes (\$000)
1			
2	All Taxes Other than Income are included on Exhibit A-3, Schedule C-7		

Schedule C11

Michigan Public Service Commission
Michigan Gas Utilities
Allowance for Funds Used During Construction
Projected 12 Month Period Ending December 31, 2022

Case No.: U-20718
Exhibit No.: A-13
Schedule No.: C11
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line			
No.	Description	Source	Projected AFUDC (\$000)
1			
2	AFUDC Debt		\$ -
3	AFUDC Equity		\$ -
4			
5	Total AFUDC		<u>\$ -</u>

Schedule D-1

Michigan Public Service Commission
Michigan Gas Utilities
Projected Rate of Return Summary
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-14
Schedule: D1
Page: 1 of 1
Witness: Joe Zgonc

										Ratios excl Def Tax	Mixed Debt (pre) Equity (after)	PreTax
										(j)	(k)	(l)
Capital Structure					Weighted Cost					Percent Capital	Weighted Cost	Weighted Cost
Line		Amount (\$000) (1)	Percent Permanent Capital (2)	Percent of Total Capital	Cost Rate %	Permanent Capital (2)	Total Cost %	Conversion Factor	Pre-Tax Return	Incl ST	Incl ST	Incl ST
No.	Description											
1												
2	Long-Term Debt	\$ 155,297	47.50%	38.74%	3.35% (3)	1.59%	1.30%		1.30%	46.49%	1.56%	1.56%
3												
4	Preferred Stock	\$ -	0.00%	0.00%	0.00% (4)	0.00%	0.00%		0.00%			
5												
6	Common Shareholders' Equity	\$ 171,644	52.50%	42.82%	10.20% (5)	5.35%	4.37%	1.347	5.88%	51.39%	5.24%	7.06%
7												
8	Total Permanent Capital	\$ 326,940	100.00%			6.95%						
9												
10	Short-Term Debt	\$ 7,080		1.77%	3.26% (6)		0.06%		0.06%	2.12%	0.07%	0.07%
11												
12	Job Development - ITC - Debt											
13	Job Development - ITC Equity											
14	Total Job Development - ITC	\$ -		0.00%	6.95%							
15												
16	Deferred Income Taxes (Net) - Federal	\$ 74,679		18.63%	0.00%		0.00%		0.00%			
17												
18	Deferred Tax Proration	\$ 0		0.00%	6.87%		0.00%		0.00%			
19												
20	Capital Structure Adjustments	\$ (7,810)		-1.95%	0.00%		0.00%		0.00%			
21												
22	Total	\$ 400,888		100.00%			5.72%		7.24%	100.00%	6.87%	8.68%

- (1) See Exh. A-12, Sch. B1
(2) Excludes Short-Term Debt, Deferred Job Development Investment Tax Credit, Deferred Investment Tax Credit and Deferred Income Taxes to calculate the rate of return for Job Development Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6
(3) See Exh. A-14, Sch. D2
(4) See Exh. A-14, Sch. D4
(5) See Exh. A-14, Sch. D5
(6) See Exh. A-14, Sch. D3

Schedule D-2

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Long-Term Debt
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-14
Schedule: D2
Page: 1 of 1
Witness: Joe Zgonc

[illegible]

Schedule D-3

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Short-Term Debt
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-14
Schedule: D3
Page: 1 of 1
Witness: Joe Zgonc

(a)		(b)	(c)
Line No.	Month	Projected Balance Outstanding (\$000)	Total Cost (\$000)
1			
2	Inter-Company Loans		
3	Dec	\$ 10,114	
4	Jan	13,633	\$ 10
5	Feb	6,042	\$ 8
6	Mar	2,569	\$ 4
7	Apr	(0)	\$ 1
8	May	(0)	\$ (0)
9	Jun	(0)	\$ (0)
10	Jul	6,429	\$ 3
11	Aug	14,528	\$ 9
12	Sep	4,455	\$ 8
13	Oct	11,949	\$ 7
14	Nov	14,305	\$ 11
15	Dec	8,015	\$ 9
16	13 month Average	<u>\$ 7,080</u>	<u>\$ 69</u>
17			
18	Credit Facility Fees and Amortization	-	133
19			
20	Guarantee Fees	-	28
21			
22	Other	-	-
23			
24	Total	<u><u>\$ 7,080</u></u>	<u><u>\$ 231</u></u>
25			
26	Average Cost of Short-Term Debt		<u><u>3.26%</u></u>

Schedule D4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Cost of Preferred Stock
Projected 13 Month Average, December 31, 2022

Case No.: U-20718
Exhibit No.: A-14
Schedule: D4
Page: 1 of 1
Witness: Joe Zgonc

(a) (b) (c) (d) (e) (f) (g) (h) (i) (j)

[illegible]

Schedule D-5

Michigan Public Service Commission
Michigan Gas Utilities
Cost of Common Shareholders' Equity
Projected 13 Month Average, December 31, 2022

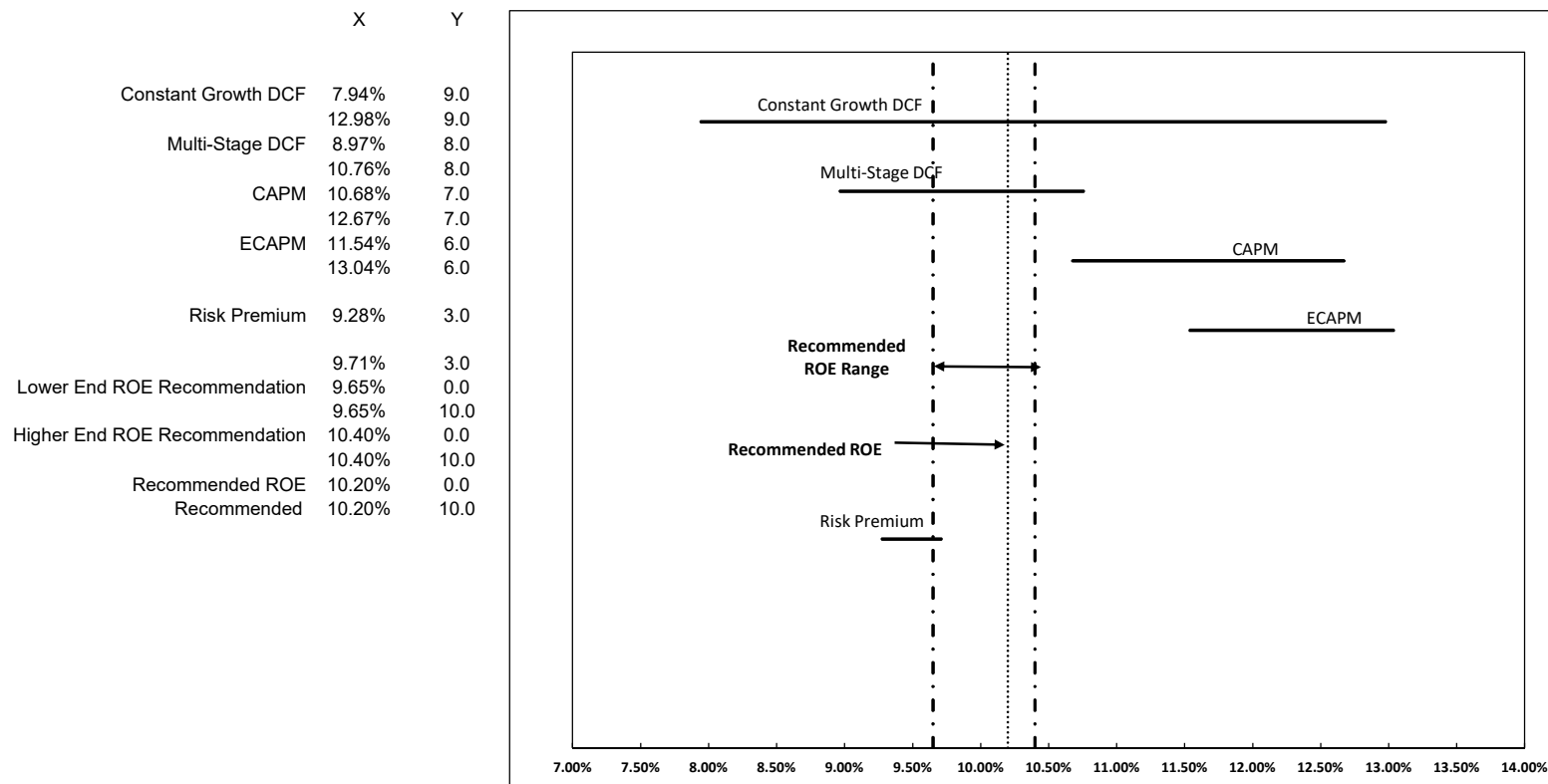
Case No.: U-20718
Exhibit No.: A-14
Schedule: D5
Page: 1 of 1
Witness: Joe Zgonc

Line No.		Adjusted Common Stock (\$000)
1		
2	Dec	164,145
3	Jan	166,626
4	Feb	171,980
5	Mar	176,000
6	Apr	177,138
7	May	176,402
8	Jun	173,854
9	Jul	171,712
10	Aug	169,759
11	Sep	167,722
12	Oct	167,573
13	Nov	170,740
14	Dec	177,714
15		
16	Average	<u>\$171,644</u> <u>10.20%</u> (1)

(1) 10.20% is the ROE requested in this docket, as explained in the testimony of Ann Bulkley

SUMMARY OF ROE ANALYSES RESULTS¹

Constant Growth DCF			
	Median Low	Median	Median High
30-Day Average	7.98%	9.92%	12.98%
90-Day Average	7.98%	9.68%	12.71%
180-Day Average	7.94%	9.61%	12.58%
Multi-Stage Growth DCF			
	Median Low	Median	Median High
30-Day Average	9.36%	9.88%	10.76%
90-Day Average	9.09%	9.71%	10.41%
180-Day Average	8.97%	9.44%	10.24%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	12.54%	12.58%	12.67%
Bloomberg Beta	11.59%	11.65%	11.80%
Long-term Avg. Beta	10.68%	10.76%	10.97%
ECAPM			
Value Line Beta	12.94%	12.96%	13.04%
Bloomberg Beta	12.23%	12.27%	12.38%
Long-term Avg. Beta	11.54%	11.60%	11.76%
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.28%	9.40%	9.71%
Risk Premium Mean Result	9.46%		



PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger	Mean CGDCF Result > 7%
Company	Ticker	Dividends	S&P or Moody's Investment Grade Credit Rating					
Atmos Energy Corporation	ATO	Yes	A	Yes	100.00%	66.55%	No	9.78%
NiSource Inc.	NI	Yes	BBB+	Yes	101.82%	61.18%	No	10.66%
Northwest Natural Gas Company	NWN	Yes	A+	Yes	100.00%	90.90%	No	8.38%
ONE Gas Inc.	OGS	Yes	A	Yes	100.00%	100.00%	No	8.82%
South Jersey Industries, Inc.	SJI	Yes	BBB	Yes	100.00%	100.00%	No	26.58%
Southwest Gas Corporation	SWX	Yes	BBB+	Yes	80.46%	100.00%	No	9.92%
Spire, Inc.	SR	Yes	A-	Yes	97.03%	100.00%	No	13.48%

Notes:

- [1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[4] Source: Form 10-K's for 2019, 2018, and 2017
[5] Source: Form 10-K's for 2019, 2018, and 2017
[6] Source: SNL Financial News Releases
[7] Source: Schedule D3, 30-day Average Share Price

30-DAY CONSTANT GROWTH DCF -- MICHIGAN GAS UTILITIES PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	\$2.50	\$91.58	2.73%	2.82%	7.00%	6.77%	7.10%	6.96%	9.59%	9.78%	9.93%
NiSource Inc.	NI	\$0.84	\$22.20	3.78%	3.91%	13.00%	1.65%	5.60%	6.75%	5.46%	10.66%	17.03%
Northwest Natural Gas Company	NWN	\$1.92	\$45.33	4.24%	4.32%	5.97%	3.10%	3.10%	4.06%	7.40%	8.38%	10.33%
ONE Gas Inc.	OGS	\$2.16	\$74.39	2.90%	2.99%	6.50%	5.00%	6.00%	5.83%	7.98%	8.82%	9.50%
South Jersey Industries, Inc.	SJI	\$1.21	\$21.93	5.52%	6.08%	12.50%	24.50%	24.50%	20.50%	18.36%	26.58%	30.69%
Southwest Gas Corporation	SWX	\$2.28	\$59.91	3.81%	3.92%	9.00%	4.00%	5.00%	6.00%	7.88%	9.92%	12.98%
Spire, Inc.	SR	\$2.60	\$62.37	4.17%	4.36%	5.50%	5.37%	16.50%	9.12%	9.65%	13.48%	21.01%
Median				3.81%	3.92%	7.00%	5.00%	6.00%	6.75%	7.98%	9.92%	12.98%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 30-day average as of January 31, 2021.

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.50 x [8])

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

[12] The Value Line Growth Rate for NWN was adjusted to exclude the negative EPS data for 2017 which resulted in an adjusted projected EPS growth rate of 5.97% (Source: Schedule D3 page 4). The growth rate for SJI published by Zacks and Yahoo! is a consensus estimate and therefore, can not be adjusted. As a result, the median was used as the measure of central tendency to account for the Zacks and Yahoo! earnings growth rate for SJI.

90-DAY CONSTANT GROWTH DCF -- MICHIGAN GAS UTILITIES GAS PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	\$2.50	\$94.91	2.63%	2.73%	7.00%	6.77%	7.10%	6.96%	9.49%	9.68%	9.83%
NiSource Inc.	NI	\$0.84	\$23.01	3.65%	3.77%	13.00%	1.65%	5.60%	6.75%	5.33%	10.52%	16.89%
Northwest Natural Gas Company	NWN	\$1.92	\$46.48	4.13%	4.21%	5.97%	3.10%	3.10%	4.06%	7.29%	8.27%	10.22%
ONE Gas Inc.	OGS	\$2.16	\$74.40	2.90%	2.99%	6.50%	5.00%	6.00%	5.83%	7.98%	8.82%	9.50%
South Jersey Industries, Inc.	SJI	\$1.21	\$21.47	5.64%	6.21%	12.50%	24.50%	24.50%	20.50%	18.49%	26.71%	30.83%
Southwest Gas Corporation	SWX	\$2.28	\$64.23	3.55%	3.66%	9.00%	4.00%	5.00%	6.00%	7.62%	9.66%	12.71%
Spire, Inc.	SR	\$2.60	\$60.42	4.30%	4.50%	5.50%	5.37%	16.50%	9.12%	9.79%	13.62%	21.16%
Median				3.65%	3.77%	7.00%	5.00%	6.00%	6.75%	7.98%	9.68%	12.71%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 90-day average as of January 31, 2021.

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.50 x [8])

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

[12] The Value Line Growth Rate for NWN was adjusted to exclude the negative EPS data for 2017 which resulted in an adjusted projected EPS growth rate of 5.97% (Source: Schedule D3, page 4). The growth rate for SJI published by Zacks and Yahoo! is a consensus estimate and therefore, can not be adjusted. As a result, the median was used as the measure of central tendency to account for the Zacks and Yahoo! earnings growth rate for SJI.

180-DAY CONSTANT GROWTH DCF -- MICHIGAN GAS UTILITIES PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	\$2.50	\$97.67	2.56%	2.65%	7.00%	6.77%	7.10%	6.96%	9.42%	9.61%	9.75%
NiSource Inc.	NI	\$0.84	\$23.22	3.62%	3.74%	13.00%	1.65%	5.60%	6.75%	5.30%	10.49%	16.85%
Northwest Natural Gas Company	NWN	\$1.92	\$50.67	3.79%	3.87%	5.97%	3.10%	3.10%	4.06%	6.95%	7.92%	9.87%
ONE Gas Inc.	OGS	\$2.16	\$75.21	2.87%	2.96%	6.50%	5.00%	6.00%	5.83%	7.94%	8.79%	9.47%
South Jersey Industries, Inc.	SJI	\$1.21	\$22.81	5.30%	5.85%	12.50%	24.50%	24.50%	20.50%	18.14%	26.35%	30.45%
Southwest Gas Corporation	SWX	\$2.28	\$66.48	3.43%	3.53%	9.00%	4.00%	5.00%	6.00%	7.50%	9.53%	12.58%
Spire, Inc.	SR	\$2.60	\$62.13	4.18%	4.38%	5.50%	5.37%	16.50%	9.12%	9.67%	13.50%	21.03%
Median				3.62%	3.74%	7.00%	5.00%	6.00%	6.75%	7.94%	9.61%	12.58%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 180-day average as of January 31, 2021.

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.50 x [8])

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

[12] The Value Line Growth Rate for NWN was adjusted to exclude the negative EPS data for 2017 which resulted in an adjusted projected EPS growth rate of 5.97% (Source: Schedule D3 page 4). The growth rate for SJI published by Zacks and Yahoo! is a consensus estimate and therefore, can not be adjusted. As a result, the median was used as the measure of central tendency to account for the Zacks and Yahoo! earnings growth rate for SJI.

**Actual and Adjusted Calculation of Northwest Natural's
Projected Earnings Growth Rate from Value Line**

	[1]	[2]	[3]
	Actual Earnings Per Share	Projected Earnings Per Share (2023-2025)	Projected Earnings Growth Rate
2017	-1.94		
2018	2.33		
2019	2.19		
Mean (2017-2019)	0.86	3.2	24.48%
Mean (2018-2019)	2.26	3.2	5.97%

Notes:

[1] Source: Value Line, November 27, 2020

[2] Source: Value Line, November 27, 2020

[3] Equals $([2] / [1])^{1/6} - 1$

30-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$91.58	\$2.50	6.96%	6.72%	6.49%	6.26%	6.02%	5.79%	5.56%	8.83%
NiSource Inc.	NI	\$22.20	\$0.84	6.75%	6.55%	6.35%	6.15%	5.96%	5.76%	5.56%	10.06%
Northwest Natural Gas Company	NWN	\$45.33	\$1.92	4.06%	4.31%	4.56%	4.81%	5.06%	5.31%	5.56%	9.82%
ONE Gas Inc.	OGS	\$74.39	\$2.16	5.83%	5.79%	5.74%	5.70%	5.65%	5.60%	5.56%	8.80%
South Jersey Industries, Inc.	SJI	\$21.93	\$1.21	20.50%	18.01%	15.52%	13.03%	10.54%	8.05%	5.56%	18.86%
Southwest Gas Corporation	SWX	\$59.91	\$2.28	6.00%	5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	9.88%
Spire, Inc.	SR	\$62.37	\$2.60	9.12%	8.53%	7.94%	7.34%	6.75%	6.15%	5.56%	11.29%
Median											9.88%

Notes:

[1] Source: Bloomberg Professional, equals 30-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Average Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$94.91	\$2.50	6.96%	6.72%	6.49%	6.26%	6.02%	5.79%	5.56%	8.72%
NiSource Inc.	NI	\$23.01	\$0.84	6.75%	6.55%	6.35%	6.15%	5.96%	5.76%	5.56%	9.90%
Northwest Natural Gas Company	NWN	\$46.48	\$1.92	4.06%	4.31%	4.56%	4.81%	5.06%	5.31%	5.56%	9.71%
ONE Gas Inc.	OGS	\$74.40	\$2.16	5.83%	5.79%	5.74%	5.70%	5.65%	5.60%	5.56%	8.80%
South Jersey Industries, Inc.	SJI	\$21.47	\$1.21	20.50%	18.01%	15.52%	13.03%	10.54%	8.05%	5.56%	19.11%
Southwest Gas Corporation	SWX	\$64.23	\$2.28	6.00%	5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	9.58%
Spire, Inc.	SR	\$60.42	\$2.60	9.12%	8.53%	7.94%	7.34%	6.75%	6.15%	5.56%	11.48%
Median											9.71%

Notes:

[1] Source: Bloomberg Professional, equals 90-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Average Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$

[5] Equals $[4] + ([9] - [3]) / 6$

[6] Equals $[5] + ([9] - [3]) / 6$

[7] Equals $[6] + ([9] - [3]) / 6$

[8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$97.67	\$2.50	6.96%	6.72%	6.49%	6.26%	6.02%	5.79%	5.56%	8.62%
NiSource Inc.	NI	\$23.22	\$0.84	6.75%	6.55%	6.35%	6.15%	5.96%	5.76%	5.56%	9.86%
Northwest Natural Gas Company	NWN	\$50.67	\$1.92	4.06%	4.31%	4.56%	4.81%	5.06%	5.31%	5.56%	9.35%
ONE Gas Inc.	OGS	\$75.21	\$2.16	5.83%	5.79%	5.74%	5.70%	5.65%	5.60%	5.56%	8.76%
South Jersey Industries, Inc.	SJI	\$22.81	\$1.21	20.50%	18.01%	15.52%	13.03%	10.54%	8.05%	5.56%	18.41%
Southwest Gas Corporation	SWX	\$66.48	\$2.28	6.00%	5.93%	5.85%	5.78%	5.71%	5.63%	5.56%	9.44%
Spire, Inc.	SR	\$62.13	\$2.60	9.12%	8.53%	7.94%	7.34%	6.75%	6.15%	5.56%	11.31%
Median											9.44%

Notes:

[1] Source: Bloomberg Professional, equals 180-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Average Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- LOW GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$91.58	\$2.50	6.77%	6.57%	6.37%	6.16%	5.96%	5.76%	5.56%	8.79%
NiSource Inc.	NI	\$22.20	\$0.84	1.65%	2.30%	2.95%	3.60%	4.26%	4.91%	5.56%	8.78%
Northwest Natural Gas Company	NWN	\$45.33	\$1.92	3.10%	3.51%	3.92%	4.33%	4.74%	5.15%	5.56%	9.56%
ONE Gas Inc.	OGS	\$74.39	\$2.16	5.00%	5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	8.63%
South Jersey Industries, Inc.	SJI	\$21.93	\$1.21	12.50%	11.34%	10.19%	9.03%	7.87%	6.72%	5.56%	14.65%
Southwest Gas Corporation	SWX	\$59.91	\$2.28	4.00%	4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.36%
Spire, Inc.	SR	\$62.37	\$2.60	5.37%	5.40%	5.43%	5.46%	5.50%	5.53%	5.56%	10.12%
Median											9.36%

Notes:

[1] Source: Bloomberg Professional, equals 30-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Minimum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- LOW GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$94.91	\$2.50	6.77%	6.57%	6.37%	6.16%	5.96%	5.76%	5.56%	8.68%
NiSource Inc.	NI	\$23.01	\$0.84	1.65%	2.30%	2.95%	3.60%	4.26%	4.91%	5.56%	8.66%
Northwest Natural Gas Company	NWN	\$46.48	\$1.92	3.10%	3.51%	3.92%	4.33%	4.74%	5.15%	5.56%	9.46%
ONE Gas Inc.	OGS	\$74.40	\$2.16	5.00%	5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	8.62%
South Jersey Industries, Inc.	SJI	\$21.47	\$1.21	12.50%	11.34%	10.19%	9.03%	7.87%	6.72%	5.56%	14.84%
Southwest Gas Corporation	SWX	\$64.23	\$2.28	4.00%	4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	9.09%
Spire, Inc.	SR	\$60.42	\$2.60	5.37%	5.40%	5.43%	5.46%	5.50%	5.53%	5.56%	10.27%
Median											9.09%

Notes:

[1] Source: Bloomberg Professional, equals 90-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Minimum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$

[5] Equals $[4] + ([9] - [3]) / 6$

[6] Equals $[5] + ([9] - [3]) / 6$

[7] Equals $[6] + ([9] - [3]) / 6$

[8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- LOW GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$97.67	\$2.50	6.77%	6.57%	6.37%	6.16%	5.96%	5.76%	5.56%	8.59%
NiSource Inc.	NI	\$23.22	\$0.84	1.65%	2.30%	2.95%	3.60%	4.26%	4.91%	5.56%	8.63%
Northwest Natural Gas Company	NWN	\$50.67	\$1.92	3.10%	3.51%	3.92%	4.33%	4.74%	5.15%	5.56%	9.12%
ONE Gas Inc.	OGS	\$75.21	\$2.16	5.00%	5.09%	5.19%	5.28%	5.37%	5.47%	5.56%	8.59%
South Jersey Industries, Inc.	SJI	\$22.81	\$1.21	12.50%	11.34%	10.19%	9.03%	7.87%	6.72%	5.56%	14.32%
Southwest Gas Corporation	SWX	\$66.48	\$2.28	4.00%	4.26%	4.52%	4.78%	5.04%	5.30%	5.56%	8.97%
Spire, Inc.	SR	\$62.13	\$2.60	5.37%	5.40%	5.43%	5.46%	5.50%	5.53%	5.56%	10.13%
Median											8.97%

Notes:

[1] Source: Bloomberg Professional, equals 180-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Minimum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$91.58	\$2.50	7.10%	6.84%	6.59%	6.33%	6.07%	5.82%	5.56%	8.86%
NiSource Inc.	NI	\$22.20	\$0.84	13.00%	11.76%	10.52%	9.28%	8.04%	6.80%	5.56%	12.06%
Northwest Natural Gas Company	NWN	\$45.33	\$1.92	5.97%	5.90%	5.83%	5.76%	5.70%	5.63%	5.56%	10.37%
ONE Gas Inc.	OGS	\$74.39	\$2.16	6.50%	6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	8.95%
South Jersey Industries, Inc.	SJI	\$21.93	\$1.21	24.50%	21.34%	18.19%	15.03%	11.87%	8.72%	5.56%	21.24%
Southwest Gas Corporation	SWX	\$59.91	\$2.28	9.00%	8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	10.76%
Spire, Inc.	SR	\$62.37	\$2.60	16.50%	14.68%	12.85%	11.03%	9.21%	7.38%	5.56%	14.13%
Median											10.76%

Notes:

[1] Source: Bloomberg Professional, equals 30-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Maximum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$94.91	\$2.50	7.10%	6.84%	6.59%	6.33%	6.07%	5.82%	5.56%	8.75%
NiSource Inc.	NI	\$23.01	\$0.84	13.00%	11.76%	10.52%	9.28%	8.04%	6.80%	5.56%	11.84%
Northwest Natural Gas Company	NWN	\$46.48	\$1.92	5.97%	5.90%	5.83%	5.76%	5.70%	5.63%	5.56%	10.25%
ONE Gas Inc.	OGS	\$74.40	\$2.16	6.50%	6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	8.94%
South Jersey Industries, Inc.	SJI	\$21.47	\$1.21	24.50%	21.34%	18.19%	15.03%	11.87%	8.72%	5.56%	21.52%
Southwest Gas Corporation	SWX	\$64.23	\$2.28	9.00%	8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	10.41%
Spire, Inc.	SR	\$60.42	\$2.60	16.50%	14.68%	12.85%	11.03%	9.21%	7.38%	5.56%	14.39%
Median											10.41%

Notes:

[1] Source: Bloomberg Professional, equals 90-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule D3, Maximum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE -- MICHIGAN GAS UTILITIES PROXY GROUP

Witness: Ann E. Bulkley

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Second Stage Growth					Third Stage Growth	ROE
					Year 6	Year 7	Year 8	Year 9	Year 10		
Atmos Energy Corporation	ATO	\$97.67	\$2.50	7.10%	6.84%	6.59%	6.33%	6.07%	5.82%	5.56%	8.65%
NiSource Inc.	NI	\$23.22	\$0.84	13.00%	11.76%	10.52%	9.28%	8.04%	6.80%	5.56%	11.79%
Northwest Natural Gas Company	NWN	\$50.67	\$1.92	5.97%	5.90%	5.83%	5.76%	5.70%	5.63%	5.56%	9.85%
ONE Gas Inc.	OGS	\$75.21	\$2.16	6.50%	6.34%	6.19%	6.03%	5.87%	5.72%	5.56%	8.91%
South Jersey Industries, Inc.	SJI	\$22.81	\$1.21	24.50%	21.34%	18.19%	15.03%	11.87%	8.72%	5.56%	20.74%
Southwest Gas Corporation	SWX	\$66.48	\$2.28	9.00%	8.43%	7.85%	7.28%	6.71%	6.13%	5.56%	10.24%
Spire, Inc.	SR	\$62.13	\$2.60	16.50%	14.68%	12.85%	11.03%	9.21%	7.38%	5.56%	14.16%
Median											10.24%

Notes:

[1] Source: Bloomberg Professional, equals 180-day average as of January 31, 2021.

[2] Source: Bloomberg Professional

[3] Source: Schedule AEB-D3, Maximum Growth Rate

[4] Equals $[3] + ([9] - [3]) / 6$ [5] Equals $[4] + ([9] - [3]) / 6$ [6] Equals $[5] + ([9] - [3]) / 6$ [7] Equals $[6] + ([9] - [3]) / 6$ [8] Equals $[7] + ([9] - [3]) / 6$

[9] Source: Schedule AEB-D5

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

CALCULATION OF LONG-TERM GDP GROWTH RATE

Real GDP (\$ Billions) [1]	
1929	\$ 1,109.4
2019	\$ 19,091.7
Compound Annual Growth Rate	3.21%
Consumer Price Index (YoY % Change) [2]	
2027-2031	2.20%
Average	2.20%
Consumer Price Index (All-Urban) [3]	
2031	3.39
2050	5.25
Compound Annual Growth Rate	2.32%
GDP Chain-type Price Index (2012=1.000) [3]	
2031	1.49
2050	2.29
Compound Annual Growth Rate	2.30%
Average Inflation Forecast	2.27%
Long-Term GDP Growth Rate	5.56%

Notes:

[1] Bureau of Economic Analysis, December 22, 2020

[2] Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14

[3] Energy Information Administration, Annual Energy Outlook 2020 at Table 20, January 29, 2020

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Current 30-day average of 30-year U.S. Treasury bond					
Company	Ticker	yield	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	1.77%	0.80	14.13%	12.36%	11.66%	12.27%
NiSource Inc.	NI	1.77%	0.85	14.13%	12.36%	12.27%	12.74%
Northwest Natural Gas Company	NWN	1.77%	0.80	14.13%	12.36%	11.66%	12.27%
ONE Gas Inc.	OGS	1.77%	0.80	14.13%	12.36%	11.66%	12.27%
South Jersey Industries, Inc.	SJI	1.77%	1.05	14.13%	12.36%	14.75%	14.59%
Southwest Gas Corporation	SWX	1.77%	0.95	14.13%	12.36%	13.51%	13.66%
Spire, Inc.	SR	1.77%	0.85	14.13%	12.36%	12.27%	12.74%
Mean						12.54%	12.94%

Notes:

- [1] Source: Bloomberg Professional
[2] Source: Value Line; dated November 27, 2020
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Near-term projected 30-year U.S. Treasury bond yield					
Company	Ticker	(Q2 2021 - Q2 2022)	Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	2.06%	0.80	14.13%	12.07%	11.71%	12.32%
NiSource Inc.	NI	2.06%	0.85	14.13%	12.07%	12.32%	12.77%
Northwest Natural Gas Company	NWN	2.06%	0.80	14.13%	12.07%	11.71%	12.32%
ONE Gas Inc.	OGS	2.06%	0.80	14.13%	12.07%	11.71%	12.32%
South Jersey Industries, Inc.	SJI	2.06%	1.05	14.13%	12.07%	14.73%	14.58%
Southwest Gas Corporation	SWX	2.06%	0.95	14.13%	12.07%	13.52%	13.68%
Spire, Inc.	SR	2.06%	0.85	14.13%	12.07%	12.32%	12.77%
Mean						12.58%	12.96%

Notes:

- [1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 2, February 1, 2021, at 2
[2] Source: Value Line; dated November 27, 2020
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Projected 30-year U.S. Treasury bond yield (2022 - 2026)					
Company	Ticker		Beta	Market Return	Market Risk Premium	CAPM ROE	ECAPM ROE
Atmos Energy Corporation	ATO	2.80%	0.80	14.13%	11.33%	11.86%	12.43%
NiSource Inc.	NI	2.80%	0.85	14.13%	11.33%	12.43%	12.85%
Northwest Natural Gas Company	NWN	2.80%	0.80	14.13%	11.33%	11.86%	12.43%
ONE Gas Inc.	OGS	2.80%	0.80	14.13%	11.33%	11.86%	12.43%
South Jersey Industries, Inc.	SJI	2.80%	1.05	14.13%	11.33%	14.69%	14.55%
Southwest Gas Corporation	SWX	2.80%	0.95	14.13%	11.33%	13.56%	13.70%
Spire, Inc.	SR	2.80%	0.85	14.13%	11.33%	12.43%	12.85%
Mean						12.67%	13.04%

Notes:

- [1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14
[2] Source: Value Line; dated November 27, 2020
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Current 30-day average of 30-year U.S. Treasury bond yield		Beta	Market Return	Market Risk Premium	ECAPM ROE
Company	Ticker					CAPM ROE	ROE
Atmos Energy Corporation	ATO	1.77%		0.75	14.13%	12.36%	11.02%
NiSource Inc.	NI	1.77%		0.80	14.13%	12.36%	11.68%
Northwest Natural Gas Company	NWN	1.77%		0.73	14.13%	12.36%	10.74%
ONE Gas Inc.	OGS	1.77%		0.83	14.13%	12.36%	12.07%
South Jersey Industries, Inc.	SJI	1.77%		0.84	14.13%	12.36%	12.12%
Southwest Gas Corporation	SWX	1.77%		0.86	14.13%	12.36%	12.36%
Spire, Inc.	SR	1.77%		0.76	14.13%	12.36%	11.15%
Mean						11.59%	12.23%

Notes:

- [1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Near-term projected 30-year U.S. Treasury bond yield (Q2 2021 - Q2 2022)		Beta	Market Return	Market Risk Premium	ECAPM ROE
Company	Ticker					CAPM ROE	ROE
Atmos Energy Corporation	ATO	2.06%		0.75	14.13%	12.07%	11.09%
NiSource Inc.	NI	2.06%		0.80	14.13%	12.07%	11.73%
Northwest Natural Gas Company	NWN	2.06%		0.73	14.13%	12.07%	10.82%
ONE Gas Inc.	OGS	2.06%		0.83	14.13%	12.07%	12.12%
South Jersey Industries, Inc.	SJI	2.06%		0.84	14.13%	12.07%	12.17%
Southwest Gas Corporation	SWX	2.06%		0.86	14.13%	12.07%	12.40%
Spire, Inc.	SR	2.06%		0.76	14.13%	12.07%	11.22%
Mean						11.65%	12.27%

Notes:

- [1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 2, February 1, 2021, at 2
[2] Source: Bloomberg Professional
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
		Projected 30-year U.S. Treasury bond yield (2022 - 2026)		Beta	Market Return	Market Risk Premium	ECAPM ROE
Company	Ticker					CAPM ROE	ROE
Atmos Energy Corporation	ATO	2.80%		0.75	14.13%	11.33%	11.28%
NiSource Inc.	NI	2.80%		0.80	14.13%	11.33%	11.88%
Northwest Natural Gas Company	NWN	2.80%		0.73	14.13%	11.33%	11.02%
ONE Gas Inc.	OGS	2.80%		0.83	14.13%	11.33%	12.24%
South Jersey Industries, Inc.	SJI	2.80%		0.84	14.13%	11.33%	12.29%
Southwest Gas Corporation	SWX	2.80%		0.86	14.13%	11.33%	12.51%
Spire, Inc.	SR	2.80%		0.76	14.13%	11.33%	11.40%
Mean						11.80%	12.38%

Notes:

- [1] Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14
[2] Source: Bloomberg Professional
[3] Source: Schedule D9
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM AVERAGE BETA

$$CAPM: K = R_f + \beta (R_m - R_f) / ECAPM: K = R_f + 0.25(R_m - R_f) + 0.75\beta (R_m - R_f)$$

	[4]	[5]	[6]	[7]	[8]	[9]
	Risk-Free Rate (R_f)	Beta (β)	Market Return (R_m)	Market Risk Premium ($R_m - R_f$)	CAPM (K)	ECAPM (K)
Current 30-day average of 30-year U.S. Treasury bond yield [1]	1.77%	0.721	14.13%	12.36%	10.68%	11.54%
Near-term projected 30-year U.S. Treasury bond yield (Q2 2021 - Q2 2022) [2]	2.06%	0.721	14.13%	12.07%	10.76%	11.60%
Projected 30-year U.S. Treasury bond yield (2022 - 2026) [3]	2.80%	0.721	14.13%	11.33%	10.97%	11.76%
				Average:	10.80%	11.63%

Notes:

- [1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 40, No. 2, February 1, 2021, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Schedule D8
[6] Source: Schedule D9
[7] Equals [6] - [4]
[8] Equals [4] + [5] x [7]
[9] Equals [4] + 0.25 x ([7]) + 0.75 x ([5] x [7])

HISTORICAL BETA - 2011 - 2020

Company	Ticker	[1] 12/31/2011	[2] 12/31/2012	[3] 12/31/2013	[4] 12/31/2014	[5] 12/31/2015	[6] 12/31/2016	[7] 12/31/2017	[8] 12/31/2018	[9] 12/31/2019	[10] 12/31/2020	[11] Average
Atmos Energy Corporation	ATO	0.70	0.70	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.72
NiSource Inc.	NI	0.85	0.80	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.73
Northwest Natural Gas Company	NWN	0.60	0.55	0.65	0.70	0.65	0.60	0.70	0.60	0.60	0.80	0.65
ONE Gas Inc.	OGS	N/A	N/A	N/A	N/A	N/A	N/A	0.70	0.65	0.65	0.80	0.70
South Jersey Industries, Inc.	SJI	0.65	0.65	0.70	0.80	0.80	0.80	0.85	0.80	0.80	1.05	0.79
Southwest Gas Corporation	SWX	0.75	0.75	0.80	0.85	0.80	0.75	0.80	0.70	0.70	0.95	0.79
Spire, Inc.	SR	0.60	0.55	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.85	0.68
Mean		0.69	0.67	0.74	0.78	0.75	0.71	0.72	0.64	0.65	0.87	0.72

Notes:

- [1] Value Line, dated December 9, 2011.
[2] Value Line, dated December 7, 2012.
[3] Value Line, dated December 6, 2013.
[4] Value Line, dated December 5, 2014.
[5] Value Line, dated December 4, 2015.
[6] Value Line, dated December 2, 2016.
[7] Value Line, dated December 1, 2017.
[8] Value Line, dated November 30, 2018.
[9] Value Line, dated November 29, 2019.
[10] Value Line, dated November 27, 2020.
[11] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.58%
[2] Estimated Weighted Average Long-Term Growth Rate	12.45%
[3] S&P 500 Estimated Required Market Return	14.13%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight in Index	[5] Current Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Est.	[8] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	0.09%	4.90%	0.00%	3.50%	0.00%
American Express Co	AXP	0.30%	1.48%	0.00%	6.00%	0.02%
Verizon Communications Inc	VZ	0.74%	4.58%	0.03%	4.00%	0.03%
Broadcom Inc	AVGO	0.59%	3.20%	0.02%	18.50%	0.11%
Boeing Co/The	BA	0.36%	n/a	n/a	-1.50%	-0.01%
Caterpillar Inc	CAT	0.32%	2.25%	0.01%	4.00%	0.01%
JPMorgan Chase & Co	JPM	1.27%	2.80%	0.04%	5.50%	0.07%
Chevron Corp	CVX	0.53%	6.06%	0.03%	10.50%	0.06%
Coca-Cola Co/The	KO	0.67%	3.41%	0.02%	6.50%	0.04%
AbbVie Inc	ABBV	0.59%	5.07%	0.03%	10.50%	0.06%
Walt Disney Co/The	DIS	0.99%	n/a	n/a	17.00%	0.17%
FleetCor Technologies Inc	FLT	0.07%	n/a	n/a	14.00%	0.01%
Extra Space Storage Inc	EXR	0.05%	3.16%	0.00%	3.00%	0.00%
Exxon Mobil Corp	XOM	0.62%	7.76%	0.05%	4.50%	0.03%
Phillips 66	PSX	0.10%	5.31%	0.01%	4.00%	0.00%
General Electric Co	GE	0.30%	0.37%	0.00%	4.00%	0.01%
HP Inc	HPQ	0.10%	3.18%	0.00%	10.00%	0.01%
Home Depot Inc/The	HD	0.95%	2.22%	0.02%	8.50%	0.08%
International Business Machines Corp	IBM	0.34%	5.47%	0.02%	-0.50%	0.00%
Johnson & Johnson	JNJ	1.39%	2.48%	0.03%	10.00%	0.14%
McDonald's Corp	MCD	0.50%	2.48%	0.01%	9.00%	0.05%
Merck & Co Inc	MRK	0.63%	3.37%	0.02%	9.00%	0.06%
3M Co	MMM	0.33%	3.35%	0.01%	4.50%	0.01%
American Water Works Co Inc	AWK	0.09%	1.38%	0.00%	8.50%	0.01%
Bank of America Corp	BAC	0.83%	2.43%	0.02%	4.00%	0.03%
Baker Hughes Co	BKR	0.00%	3.58%	0.00%	n/a	n/a
Pfizer Inc	PFE	0.65%	4.35%	0.03%	8.50%	0.06%
Procter & Gamble Co/The	PG	1.02%	2.47%	0.03%	8.00%	0.08%
AT&T Inc	T	0.66%	7.27%	0.05%	5.50%	0.04%
Travelers Cos Inc/The	TRV	0.11%	2.49%	0.00%	9.50%	0.01%
Raytheon Technologies Corp	RTX	0.33%	2.85%	0.01%	-6.00%	-0.02%
Analog Devices Inc	ADI	0.18%	1.68%	0.00%	8.50%	0.02%
Walmart Inc	WMT	1.29%	1.54%	0.02%	8.00%	0.10%
Cisco Systems Inc/Delaware	CSCO	0.61%	3.23%	0.02%	7.00%	0.04%
Intel Corp	INTC	0.73%	2.50%	0.02%	7.00%	0.05%
General Motors Co	GM	0.24%	n/a	n/a	4.00%	0.01%
Microsoft Corp	MSFT	5.68%	0.97%	0.05%	13.50%	0.77%
Dollar General Corp	DG	0.15%	0.74%	0.00%	13.00%	0.02%
Cigna Corp	CI	0.25%	1.84%	0.00%	11.50%	0.03%
Kinder Morgan Inc	KMI	0.10%	7.46%	0.01%	18.50%	0.02%
Citigroup Inc	C	0.39%	3.52%	0.01%	10.00%	0.04%
American International Group Inc	AIG	0.10%	3.42%	0.00%	28.50%	0.03%
Honeywell International Inc	HON	0.44%	1.90%	0.01%	8.00%	0.04%
Altria Group Inc	MO	0.25%	8.37%	0.02%	6.50%	0.02%
HCA Healthcare Inc	HCA	0.18%	n/a	n/a	11.00%	0.02%
Under Armour Inc	UA	0.01%	n/a	n/a	11.00%	0.00%
International Paper Co	IP	0.06%	4.07%	0.00%	6.50%	0.00%
Hewlett Packard Enterprise Co	HPE	0.05%	3.89%	0.00%	2.50%	0.00%
Abbott Laboratories	ABT	0.71%	1.46%	0.01%	12.00%	0.09%
Aflac Inc	AFL	0.10%	2.92%	0.00%	8.50%	0.01%
Air Products and Chemicals Inc	APD	0.19%	2.25%	0.00%	12.50%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.05%	n/a	n/a	-0.50%	0.00%
Hess Corp	HES	0.00%	1.85%	0.00%	n/a	n/a
Archer-Daniels-Midland Co	ADM	0.09%	2.96%	0.00%	9.00%	0.01%
Automatic Data Processing Inc	ADP	0.23%	2.25%	0.01%	9.00%	0.02%
Verisk Analytics Inc	VRSK	0.10%	0.59%	0.00%	11.50%	0.01%
AutoZone Inc	AZO	0.08%	n/a	n/a	12.00%	0.01%
Avery Dennison Corp	AVY	0.04%	1.64%	0.00%	11.00%	0.00%
Enphase Energy Inc	ENPH	0.07%	n/a	n/a	40.00%	0.03%
MSCI Inc	MSCI	0.11%	0.79%	0.00%	17.00%	0.02%
Ball Corp	BLL	0.09%	0.68%	0.00%	18.00%	0.02%
Carrier Global Corp	CARR	0.00%	1.25%	0.00%	n/a	n/a
Bank of New York Mellon Corp/The	BK	0.11%	3.11%	0.00%	3.00%	0.00%
Otis Worldwide Corp	OTIS	0.00%	1.24%	0.00%	n/a	n/a
Baxter International Inc	BAX	0.13%	1.28%	0.00%	9.00%	0.01%
Becton Dickinson and Co	BDX	0.25%	1.27%	0.00%	9.00%	0.02%
Berkshire Hathaway Inc	BRK/B	1.01%	n/a	n/a	6.00%	0.06%
Best Buy Co Inc	BBY	0.09%	2.02%	0.00%	9.00%	0.01%
Boston Scientific Corp	BSX	0.16%	n/a	n/a	12.50%	0.02%
Bristol-Myers Squibb Co	BMJ	0.45%	3.19%	0.01%	12.50%	0.06%
Fortune Brands Home & Security Inc	FBHS	0.04%	1.21%	0.00%	8.50%	0.00%
Brown-Forman Corp	BF/B	0.07%	1.00%	0.00%	12.00%	0.01%
Cabot Oil & Gas Corp	COG	0.02%	2.18%	0.00%	11.50%	0.00%
Campbell Soup Co	CPB	0.05%	3.08%	0.00%	4.00%	0.00%
Kansas City Southern	KSU	0.06%	0.87%	0.00%	11.50%	0.01%
Hilton Worldwide Holdings Inc	HLT	0.09%	n/a	n/a	11.00%	0.01%
Carnival Corp	CCL	0.06%	n/a	n/a	-10.00%	-0.01%
Qorvo Inc	QRVO	0.06%	n/a	n/a	37.00%	0.02%
Lumen Technologies Inc	LUMN	0.04%	8.08%	0.00%	2.50%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4]	[5]	[6]	[7]	[8]
		Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
UDR Inc	UDR	0.04%	3.75%	0.00%	3.50%	0.00%
Clorox Co/The	CLX	0.09%	2.12%	0.00%	5.00%	0.00%
Paycom Software Inc	PAYC	0.07%	n/a	n/a	23.00%	0.02%
CMS Energy Corp	CMS	0.05%	3.06%	0.00%	7.50%	0.00%
Newell Brands Inc	NWL	0.03%	3.83%	0.00%	4.50%	0.00%
Colgate-Palmolive Co	CL	0.22%	2.26%	0.00%	5.00%	0.01%
Comerica Inc	CMA	0.03%	4.76%	0.00%	0.50%	0.00%
IPG Photonics Corp	IPGP	0.04%	n/a	n/a	10.00%	0.00%
Conagra Brands Inc	CAG	0.05%	3.18%	0.00%	5.50%	0.00%
Consolidated Edison Inc	ED	0.08%	4.38%	0.00%	3.00%	0.00%
SL Green Realty Corp	SLG	0.02%	5.39%	0.00%	-1.50%	0.00%
Corning Inc	GLW	0.09%	2.45%	0.00%	13.50%	0.01%
Cummins Inc	CM	0.11%	2.30%	0.00%	4.00%	0.00%
Danaher Corp	DHR	0.55%	0.30%	0.00%	17.00%	0.09%
Target Corp	TGT	0.29%	1.50%	0.00%	13.00%	0.04%
Deere & Co	DE	0.29%	1.05%	0.00%	5.00%	0.01%
Dominion Energy Inc	D	0.19%	3.46%	0.01%	6.00%	0.01%
Dover Corp	DOV	0.05%	1.70%	0.00%	6.50%	0.00%
Alliant Energy Corp	LNT	0.04%	3.31%	0.00%	5.50%	0.00%
Duke Energy Corp	DUK	0.22%	4.11%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	0.03%	5.04%	0.00%	14.50%	0.00%
Eaton Corp PLC	ETN	0.15%	2.48%	0.00%	4.00%	0.01%
Ecolab Inc	ECL	0.19%	0.94%	0.00%	8.50%	0.02%
PerkinElmer Inc	PKI	0.05%	0.19%	0.00%	17.50%	0.01%
Emerson Electric Co	EMR	0.15%	2.55%	0.00%	9.50%	0.01%
EOG Resources Inc	EOG	0.10%	2.94%	0.00%	7.50%	0.01%
Aon PLC	AON	0.15%	0.91%	0.00%	7.50%	0.01%
Entergy Corp	ETR	0.06%	3.99%	0.00%	3.00%	0.00%
Equifax Inc	EFX	0.07%	0.88%	0.00%	6.50%	0.00%
IQVIA Holdings Inc	IQV	0.11%	n/a	n/a	11.00%	0.01%
Gartner Inc	IT	0.04%	n/a	n/a	12.00%	0.01%
FedEx Corp	FDX	0.20%	1.10%	0.00%	8.50%	0.02%
FMC Corp	FMC	0.05%	1.77%	0.00%	11.50%	0.01%
Ford Motor Co	F	0.13%	n/a	n/a	11.50%	0.02%
NextEra Energy Inc	NEE	0.51%	1.73%	0.01%	9.50%	0.05%
Franklin Resources Inc	BEN	0.04%	4.26%	0.00%	11.50%	0.00%
Freeport-McMoRan Inc	FCX	0.13%	n/a	n/a	23.00%	0.03%
Gap Inc/The	GPS	0.02%	4.79%	0.00%	2.50%	0.00%
DexCom Inc	DXCM	0.00%	n/a	n/a	n/a	n/a
General Dynamics Corp	GD	0.14%	3.00%	0.00%	6.00%	0.01%
General Mills Inc	GIS	0.12%	3.51%	0.00%	4.00%	0.00%
Genuine Parts Co	GPC	0.04%	3.37%	0.00%	7.00%	0.00%
Atmos Energy Corp	ATO	0.04%	2.81%	0.00%	7.00%	0.00%
WW Grainger Inc	GWV	0.06%	1.68%	0.00%	7.50%	0.00%
Halliburton Co	HAL	0.05%	1.02%	0.00%	1.50%	0.00%
L3Harris Technologies Inc	LHX	0.00%	2.38%	0.00%	n/a	n/a
Healthpeak Properties Inc	PEAK	0.05%	4.99%	0.00%	-15.00%	-0.01%
Catalent Inc	CTLT	0.06%	n/a	n/a	21.00%	0.01%
Fortive Corp	FTV	0.07%	0.42%	0.00%	8.50%	0.01%
Hershey Co/The	HSY	0.07%	2.21%	0.00%	5.00%	0.00%
Synchrony Financial	SYF	0.06%	2.62%	0.00%	4.50%	0.00%
Hormel Foods Corp	HRL	0.08%	2.09%	0.00%	10.00%	0.01%
Arthur J Gallagher & Co	AJG	0.07%	1.66%	0.00%	13.00%	0.01%
Mondelez International Inc	MDLZ	0.26%	2.27%	0.01%	8.00%	0.02%
CenterPoint Energy Inc	CNP	0.04%	3.03%	0.00%	5.00%	0.00%
Humana Inc	HUM	0.16%	0.65%	0.00%	10.50%	0.02%
Willis Towers Watson PLC	WLTW	0.08%	1.40%	0.00%	11.50%	0.01%
Illinois Tool Works Inc	ITW	0.20%	2.35%	0.00%	9.00%	0.02%
CDW Corp/DE	CDW	0.06%	1.22%	0.00%	11.00%	0.01%
Trane Technologies PLC	TT	0.00%	1.48%	0.00%	n/a	n/a
Interpublic Group of Cos Inc/The	IPG	0.03%	4.24%	0.00%	10.00%	0.00%
International Flavors & Fragrances Inc	IFF	0.04%	2.74%	0.00%	6.00%	0.00%
Jacobs Engineering Group Inc	J	0.04%	0.83%	0.00%	14.50%	0.01%
Hanesbrands Inc	HBI	0.02%	3.92%	0.00%	3.50%	0.00%
Kellogg Co	K	0.07%	3.87%	0.00%	2.50%	0.00%
Broadridge Financial Solutions Inc	BR	0.05%	1.63%	0.00%	10.50%	0.01%
Perrigo Co PLC	PRGO	0.02%	2.11%	0.00%	3.50%	0.00%
Kimberly-Clark Corp	KMB	0.15%	3.45%	0.01%	6.50%	0.01%
Kimco Realty Corp	KIM	0.02%	3.88%	0.00%	5.00%	0.00%
Oracle Corp	ORCL	0.58%	1.59%	0.01%	10.50%	0.06%
Kroger Co/The	KR	0.09%	2.09%	0.00%	7.50%	0.01%
Leggett & Platt Inc	LEG	0.02%	3.90%	0.00%	8.00%	0.00%
Lennar Corp	LEN	0.07%	1.20%	0.00%	9.50%	0.01%
Eli Lilly and Co	LLY	0.65%	1.63%	0.01%	10.00%	0.06%
L Brands Inc	LB	0.04%	n/a	n/a	16.00%	0.01%
Charter Communications Inc	CHTR	0.38%	n/a	n/a	36.50%	0.14%
Lincoln National Corp	LNC	0.03%	3.69%	0.00%	9.50%	0.00%
Loews Corp	L	0.04%	0.55%	0.00%	13.00%	0.01%
Lowe's Cos Inc	LOW	0.40%	1.44%	0.01%	14.50%	0.06%
Xerox Holdings Corp	XR	0.01%	4.76%	0.00%	5.00%	0.00%
IDEX Corp	IEX	0.05%	1.07%	0.00%	7.50%	0.00%
Marsh & McLennan Cos Inc	MMC	0.18%	1.69%	0.00%	9.00%	0.02%
Masco Corp	MAS	0.05%	1.03%	0.00%	9.00%	0.00%
S&P Global Inc	SPGI	0.25%	0.97%	0.00%	8.50%	0.02%
Medtronic PLC	MDT	0.49%	2.08%	0.01%	6.50%	0.03%
Viatis Inc	VTRS	0.00%	n/a	n/a	n/a	n/a
CVS Health Corp	CVS	0.30%	2.79%	0.01%	6.00%	0.02%
DuPont de Nemours Inc	DD	0.00%	1.51%	0.00%	n/a	n/a
Micron Technology Inc	MU	0.28%	n/a	n/a	11.50%	0.03%

STANDARD AND POOR'S 500 INDEX

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		Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Motorola Solutions Inc	MSI	0.09%	1.70%	0.00%	8.00%	0.01%
Cboe Global Markets Inc	CBOE	0.03%	1.83%	0.00%	12.50%	0.00%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	8.00%	0.01%
Newmont Corp	NEM	0.16%	2.68%	0.00%	19.50%	0.03%
NIKE Inc	NKE	0.55%	0.82%	0.00%	27.00%	0.15%
NiSource Inc	NI	0.03%	3.97%	0.00%	13.00%	0.00%
Norfolk Southern Corp	NSC	0.19%	1.67%	0.00%	10.50%	0.02%
Principal Financial Group Inc	PFG	0.04%	4.55%	0.00%	5.50%	0.00%
Eversource Energy	ES	0.10%	2.59%	0.00%	5.50%	0.01%
Northrop Grumman Corp	NOC	0.16%	2.02%	0.00%	11.00%	0.02%
Wells Fargo & Co	WFC	0.40%	1.34%	0.01%	5.00%	0.02%
Nucor Corp	NUE	0.05%	3.32%	0.00%	3.00%	0.00%
PVH Corp	PVH	0.02%	n/a	n/a	3.50%	0.00%
Occidental Petroleum Corp	OXY	0.06%	0.20%	0.00%	14.50%	0.01%
Omnicom Group Inc	OMC	0.04%	4.17%	0.00%	5.50%	0.00%
ONEOK Inc	OKE	0.06%	9.39%	0.01%	10.00%	0.01%
Raymond James Financial Inc	RJF	0.04%	1.56%	0.00%	6.00%	0.00%
Parker-Hannifin Corp	PH	0.11%	1.33%	0.00%	11.50%	0.01%
Rollins Inc	ROL	0.06%	0.89%	0.00%	12.00%	0.01%
PPL Corp	PPL	0.07%	6.00%	0.00%	2.50%	0.00%
ConocoPhillips	COP	0.18%	4.30%	0.01%	10.50%	0.02%
PulteGroup Inc	PHM	0.04%	1.29%	0.00%	10.00%	0.00%
Pinnacle West Capital Corp	PNW	0.03%	4.41%	0.00%	4.50%	0.00%
PNC Financial Services Group Inc/The	PNC	0.20%	3.21%	0.01%	3.00%	0.01%
PPG Industries Inc	PPG	0.10%	1.60%	0.00%	3.00%	0.00%
Progressive Corp/The	PGR	0.17%	0.46%	0.00%	9.50%	0.02%
Public Service Enterprise Group Inc	PEG	0.09%	3.47%	0.00%	5.00%	0.00%
Robert Half International Inc	RHI	0.02%	2.01%	0.00%	6.00%	0.00%
Edison International	EIX	0.07%	4.56%	0.00%	12.00%	0.01%
Schlumberger NV	SLB	0.10%	2.25%	0.00%	0.00%	0.00%
Charles Schwab Corp/The	SCHW	0.30%	1.40%	0.00%	7.50%	0.02%
Sherwin-Williams Co/The	SHW	0.20%	0.77%	0.00%	10.00%	0.02%
West Pharmaceutical Services Inc	WST	0.07%	0.23%	0.00%	17.00%	0.01%
J M Smucker Co/The	SJM	0.04%	3.09%	0.00%	2.50%	0.00%
Snap-on Inc	SNA	0.03%	2.73%	0.00%	5.00%	0.00%
AMETEK Inc	AME	0.08%	0.64%	0.00%	12.50%	0.01%
Southern Co/The	SO	0.20%	4.34%	0.01%	3.00%	0.01%
Truist Financial Corp	TFC	0.21%	3.75%	0.01%	7.00%	0.01%
Southwest Airlines Co	LUV	0.08%	n/a	n/a	0.00%	0.00%
W R Berkley Corp	WRB	0.04%	0.77%	0.00%	10.00%	0.00%
Stanley Black & Decker Inc	SWK	0.09%	1.61%	0.00%	7.50%	0.01%
Public Storage	PSA	0.13%	3.51%	0.00%	4.00%	0.01%
Arista Networks Inc	ANET	0.08%	n/a	n/a	5.50%	0.00%
Sysco Corp	SY	0.12%	2.52%	0.00%	11.50%	0.01%
Corteva Inc	CTVA	0.00%	1.30%	0.00%	n/a	n/a
Texas Instruments Inc	TXN	0.49%	2.46%	0.01%	4.00%	0.02%
Textron Inc	TXT	0.03%	0.18%	0.00%	8.50%	0.00%
Thermo Fisher Scientific Inc	TMO	0.66%	0.17%	0.00%	17.00%	0.11%
TJX Cos Inc/The	TJX	0.25%	1.62%	0.00%	12.00%	0.03%
Globe Life Inc	GL	0.03%	0.83%	0.00%	8.00%	0.00%
Johnson Controls International plc	JCI	0.12%	2.09%	0.00%	8.00%	0.01%
Ulta Beauty Inc	ULTA	0.05%	n/a	n/a	7.00%	0.00%
Union Pacific Corp	UNP	0.43%	1.96%	0.01%	10.50%	0.05%
Keysight Technologies Inc	KEYS	0.09%	n/a	n/a	17.00%	0.01%
UnitedHealth Group Inc	UNH	1.03%	1.50%	0.02%	12.00%	0.12%
Unum Group	UNM	0.02%	4.91%	0.00%	3.50%	0.00%
Marathon Oil Corp	MRO	0.02%	1.66%	0.00%	13.00%	0.00%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	13.50%	0.01%
Bio-Rad Laboratories Inc	BIO	0.05%	n/a	n/a	11.50%	0.01%
Ventas Inc	VTR	0.06%	3.91%	0.00%	1.50%	0.00%
VF Corp	VFC	0.10%	2.55%	0.00%	6.00%	0.01%
Vornado Realty Trust	VNO	0.02%	5.33%	0.00%	-20.00%	0.00%
Vulcan Materials Co	VMC	0.06%	0.91%	0.00%	12.50%	0.01%
Weyerhaeuser Co	WY	0.08%	2.18%	0.00%	20.50%	0.02%
Whirlpool Corp	WHR	0.04%	2.70%	0.00%	5.00%	0.00%
Williams Cos Inc/The	WMB	0.08%	7.72%	0.01%	12.00%	0.01%
WEC Energy Group Inc	WEC	0.09%	3.05%	0.00%	6.00%	0.01%
Adobe Inc	ADBE	0.71%	n/a	n/a	14.00%	0.10%
AES Corp/The	AES	0.05%	2.47%	0.00%	24.00%	0.01%
Amgen Inc	AMGN	0.46%	2.92%	0.01%	6.50%	0.03%
Apple Inc	AAPL	7.19%	0.62%	0.04%	16.00%	1.15%
Autodesk Inc	ADSK	0.00%	n/a	n/a	n/a	n/a
Cintas Corp	CTAS	0.11%	0.94%	0.00%	13.50%	0.01%
Comcast Corp	CMCSA	0.73%	2.02%	0.01%	8.00%	0.06%
Molson Coors Beverage Co	TAP	0.03%	n/a	n/a	5.50%	0.00%
KLA Corp	KLAC	0.14%	1.29%	0.00%	15.50%	0.02%
Marriott International Inc/MD	MAR	0.12%	n/a	n/a	4.00%	0.00%
McCormick & Co Inc/MD	MKC	0.07%	1.52%	0.00%	6.50%	0.00%
PACCAR Inc	PCAR	0.10%	1.40%	0.00%	3.50%	0.00%
Costco Wholesale Corp	COST	0.51%	0.79%	0.00%	11.00%	0.06%
First Republic Bank/CA	FRC	0.08%	0.55%	0.00%	10.50%	0.01%
Stryker Corp	SYK	0.27%	1.14%	0.00%	11.00%	0.03%
Tyson Foods Inc	TSN	0.06%	2.77%	0.00%	6.50%	0.00%
Lamb Weston Holdings Inc	LW	0.04%	1.26%	0.00%	4.00%	0.00%
Applied Materials Inc	AMAT	0.29%	0.91%	0.00%	8.50%	0.02%
American Airlines Group Inc	AAL	0.03%	n/a	n/a	-6.50%	0.00%
Cardinal Health Inc	CAH	0.05%	3.62%	0.00%	13.00%	0.01%
Cerner Corp	CERN	0.08%	1.10%	0.00%	9.00%	0.01%
Cincinnati Financial Corp	CINF	0.04%	3.00%	0.00%	10.50%	0.00%

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]
Name	Ticker	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
ViacomCBS Inc	VIAC	0.09%	1.98%	0.00%	8.00%	0.01%
DR Horton Inc	DHI	0.09%	1.04%	0.00%	12.00%	0.01%
Flowserve Corp	FLS	0.02%	2.25%	0.00%	12.50%	0.00%
Electronic Arts Inc	EA	0.13%	0.47%	0.00%	9.50%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.16%	0.00%	6.50%	0.00%
Fastenal Co	FAST	0.08%	2.46%	0.00%	8.00%	0.01%
M&T Bank Corp	MTB	0.06%	3.32%	0.00%	4.00%	0.00%
Xcel Energy Inc	XEL	0.11%	2.69%	0.00%	6.00%	0.01%
Fiserv Inc	FISV	0.22%	n/a	n/a	14.00%	0.03%
Fifth Third Bancorp	FITB	0.07%	3.73%	0.00%	1.00%	0.00%
Gilead Sciences Inc	GILD	0.27%	4.15%	0.01%	3.50%	0.01%
Hasbro Inc	HAS	0.04%	2.90%	0.00%	9.00%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.04%	4.54%	0.00%	2.50%	0.00%
Welltower Inc	WELL	0.08%	4.03%	0.00%	3.50%	0.00%
Biogen Inc	BIIB	0.14%	n/a	n/a	7.00%	0.01%
Northern Trust Corp	NTRS	0.06%	3.14%	0.00%	4.50%	0.00%
Packaging Corp of America	PKG	0.04%	2.97%	0.00%	4.00%	0.00%
Paychex Inc	PAYX	0.10%	2.84%	0.00%	6.50%	0.01%
People's United Financial Inc	PBCT	0.02%	5.27%	0.00%	2.50%	0.00%
QUALCOMM Inc	QCOM	0.58%	1.66%	0.01%	15.50%	0.09%
Roper Technologies Inc	ROP	0.13%	0.57%	0.00%	10.00%	0.01%
Ross Stores Inc	ROST	0.13%	n/a	n/a	7.50%	0.01%
IDEXX Laboratories Inc	IDXX	0.13%	n/a	n/a	15.00%	0.02%
Starbucks Corp	SBUX	0.37%	1.86%	0.01%	13.50%	0.05%
KeyCorp	KEY	0.05%	4.39%	0.00%	4.50%	0.00%
Fox Corp	FOXA	0.00%	1.48%	0.00%	n/a	n/a
Fox Corp	FOX	0.00%	1.54%	0.00%	n/a	n/a
State Street Corp	STT	0.08%	2.97%	0.00%	5.00%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	0.02%	n/a	n/a	-4.50%	0.00%
US Bancorp	USB	0.21%	3.92%	0.01%	0.50%	0.00%
A O Smith Corp	AOS	0.02%	1.92%	0.00%	5.00%	0.00%
NortonLifeLock Inc	NLOK	0.04%	2.37%	0.00%	6.50%	0.00%
T Rowe Price Group Inc	TROW	0.12%	2.30%	0.00%	8.00%	0.01%
Waste Management Inc	WM	0.15%	1.96%	0.00%	7.50%	0.01%
Constellation Brands Inc	STZ	0.12%	1.42%	0.00%	7.50%	0.01%
Xilinx Inc	XLNX	0.10%	n/a	n/a	7.50%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.04%	0.75%	0.00%	5.50%	0.00%
Zions Bancorp NA	ZION	0.02%	3.08%	0.00%	6.50%	0.00%
Alaska Air Group Inc	ALK	0.02%	n/a	n/a	0.50%	0.00%
Invesco Ltd	IVZ	0.03%	3.01%	0.00%	2.50%	0.00%
Linde PLC	LIN	0.00%	1.73%	0.00%	n/a	n/a
Intuit Inc	INTU	0.31%	0.65%	0.00%	15.50%	0.05%
Morgan Stanley	MS	0.39%	2.09%	0.01%	7.50%	0.03%
Microchip Technology Inc	MCHP	0.12%	1.08%	0.00%	9.00%	0.01%
Chubb Ltd	CB	0.21%	2.14%	0.00%	9.50%	0.02%
Hologic Inc	HOLX	0.07%	n/a	n/a	20.50%	0.01%
Citizens Financial Group Inc	CFG	0.05%	4.28%	0.00%	12.00%	0.01%
O'Reilly Automotive Inc	ORLY	0.10%	n/a	n/a	14.00%	0.01%
Allstate Corp/The	ALL	0.11%	2.02%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.02%	1.31%	0.00%	8.00%	0.00%
Equity Residential	EQR	0.07%	3.91%	0.00%	1.00%	0.00%
BorgWarner Inc	BWA	0.03%	1.62%	0.00%	4.00%	0.00%
Host Hotels & Resorts Inc	HST	0.03%	n/a	n/a	-9.00%	0.00%
Incyte Corp	INCY	0.00%	n/a	n/a	n/a	n/a
Simon Property Group Inc	SPG	0.10%	5.60%	0.01%	-1.00%	0.00%
Eastman Chemical Co	EMN	0.04%	2.81%	0.00%	5.00%	0.00%
Twitter Inc	TWTR	0.13%	n/a	n/a	29.00%	0.04%
AvalonBay Communities Inc	AVB	0.07%	3.89%	0.00%	1.00%	0.00%
Prudential Financial Inc	PRU	0.10%	5.62%	0.01%	5.00%	0.01%
United Parcel Service Inc	UPS	0.36%	2.61%	0.01%	8.00%	0.03%
Walgreens Boots Alliance Inc	WBA	0.14%	3.72%	0.01%	6.00%	0.01%
STERIS PLC	STE	0.05%	0.86%	0.00%	10.00%	0.01%
McKesson Corp	MCK	0.09%	0.96%	0.00%	9.00%	0.01%
Lockheed Martin Corp	LMT	0.29%	3.23%	0.01%	8.50%	0.02%
AmerisourceBergen Corp	ABC	0.07%	1.69%	0.00%	7.00%	0.00%
Capital One Financial Corp	COF	0.16%	0.38%	0.00%	5.50%	0.01%
Waters Corp	WAT	0.05%	n/a	n/a	6.00%	0.00%
Dollar Tree Inc	DLTR	0.08%	n/a	n/a	8.50%	0.01%
Darden Restaurants Inc	DRI	0.05%	1.27%	0.00%	7.50%	0.00%
Domino's Pizza Inc	DPZ	0.05%	0.84%	0.00%	14.00%	0.01%
NVR Inc	NVR	0.05%	n/a	n/a	9.50%	0.01%
NetApp Inc	NTAP	0.05%	2.89%	0.00%	6.00%	0.00%
Citrix Systems Inc	CTXS	0.05%	1.11%	0.00%	9.00%	0.00%
DXC Technology Co	DXC	0.02%	n/a	n/a	2.50%	0.00%
Old Dominion Freight Line Inc	ODFL	0.07%	0.31%	0.00%	9.00%	0.01%
DaVita Inc	DVA	0.04%	n/a	n/a	13.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.06%	2.71%	0.00%	8.50%	0.00%
Iron Mountain Inc	IRM	0.03%	7.35%	0.00%	8.50%	0.00%
Estee Lauder Cos Inc/The	EL	0.17%	0.90%	0.00%	12.00%	0.02%
Cadence Design Systems Inc	CDNS	0.12%	n/a	n/a	13.00%	0.02%
Tyler Technologies Inc	TYL	0.06%	n/a	n/a	10.50%	0.01%
Universal Health Services Inc	UHS	0.03%	n/a	n/a	11.00%	0.00%
Skyworks Solutions Inc	SWKS	0.09%	1.18%	0.00%	11.50%	0.01%
NOV Inc	NOV	0.00%	n/a	n/a	n/a	n/a
Quest Diagnostics Inc	DGX	0.06%	1.73%	0.00%	9.00%	0.01%
Activision Blizzard Inc	ATVI	0.23%	0.45%	0.00%	14.50%	0.03%
Rockwell Automation Inc	ROK	0.09%	1.72%	0.00%	7.00%	0.01%
Kraft Heinz Co/The	KHC	0.13%	4.77%	0.01%	-0.50%	0.00%
American Tower Corp	AMT	0.33%	2.13%	0.01%	7.50%	0.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4]	[5]	[6]	[7]	[8]
		Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
HollyFrontier Corp	HFC	0.00%	4.92%	0.00%	n/a	n/a
Regeneron Pharmaceuticals Inc	REGN	0.17%	n/a	n/a	10.50%	0.02%
Amazon.com Inc	AMZN	5.22%	n/a	n/a	35.50%	1.85%
Jack Henry & Associates Inc	JKHY	0.04%	1.19%	0.00%	10.50%	0.00%
Ralph Lauren Corp	RL	0.02%	n/a	n/a	6.50%	0.00%
Boston Properties Inc	BXP	0.05%	4.29%	0.00%	4.00%	0.00%
Amphenol Corp	APH	0.12%	0.93%	0.00%	11.00%	0.01%
Howmet Aerospace Inc	HWM	0.03%	n/a	n/a	12.00%	0.00%
Pioneer Natural Resources Co	PXD	0.08%	1.82%	0.00%	10.50%	0.01%
Valero Energy Corp	VLO	0.07%	6.95%	0.01%	2.50%	0.00%
Synopsys Inc	SNPS	0.13%	n/a	n/a	13.50%	0.02%
Western Union Co/The	WU	0.03%	4.04%	0.00%	6.00%	0.00%
Etsy Inc	ETSY	0.08%	n/a	n/a	32.00%	0.03%
CH Robinson Worldwide Inc	CHRW	0.04%	2.38%	0.00%	8.00%	0.00%
Accenture PLC	ACN	0.52%	1.46%	0.01%	8.00%	0.04%
TransDigm Group Inc	TDG	0.10%	n/a	n/a	8.00%	0.01%
Yum! Brands Inc	YUM	0.10%	1.85%	0.00%	10.50%	0.01%
Prologis Inc	PLD	0.25%	2.25%	0.01%	6.00%	0.01%
FirstEnergy Corp	FE	0.05%	5.07%	0.00%	8.50%	0.00%
VeriSign Inc	VRSN	0.07%	n/a	n/a	9.50%	0.01%
Quanta Services Inc	PWR	0.03%	0.34%	0.00%	12.50%	0.00%
Henry Schein Inc	HSIC	0.03%	n/a	n/a	5.00%	0.00%
Ameren Corp	AEE	0.06%	2.83%	0.00%	6.00%	0.00%
ANSYS Inc	ANSS	0.10%	n/a	n/a	10.00%	0.01%
NVIDIA Corp	NVDA	1.04%	0.12%	0.00%	13.50%	0.14%
Sealed Air Corp	SEE	0.02%	1.51%	0.00%	26.00%	0.01%
Cognizant Technology Solutions Corp	CTSH	0.14%	1.13%	0.00%	5.00%	0.01%
SVB Financial Group	SIVB	0.07%	n/a	n/a	19.50%	0.01%
Intuitive Surgical Inc	ISRG	0.29%	n/a	n/a	12.50%	0.04%
Take-Two Interactive Software Inc	TTWO	0.07%	n/a	n/a	16.50%	0.01%
Republic Services Inc	RSG	0.09%	1.88%	0.00%	9.00%	0.01%
eBay Inc	EBAY	0.13%	1.13%	0.00%	18.50%	0.02%
Goldman Sachs Group Inc/The	GS	0.30%	1.84%	0.01%	6.50%	0.02%
SBA Communications Corp	SBAC	0.10%	0.69%	0.00%	36.50%	0.04%
Sempra Energy	SRE	0.12%	3.38%	0.00%	11.00%	0.01%
Moody's Corp	MCO	0.16%	0.84%	0.00%	9.50%	0.02%
Booking Holdings Inc	BKNG	0.26%	n/a	n/a	7.00%	0.02%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	7.00%	0.00%
Akamai Technologies Inc	AKAM	0.06%	n/a	n/a	15.00%	0.01%
MarketAxess Holdings Inc	MKTX	0.07%	0.49%	0.00%	17.00%	0.01%
Devon Energy Corp	DVN	0.00%	2.67%	0.00%	n/a	n/a
Alphabet Inc	GOOGL	0.00%	n/a	n/a	n/a	n/a
Teleflex Inc	TFX	0.06%	0.36%	0.00%	15.00%	0.01%
Allegion plc	ALLE	0.03%	1.20%	0.00%	9.00%	0.00%
Netflix Inc	NFLX	0.77%	n/a	n/a	24.00%	0.18%
Agilent Technologies Inc	A	0.12%	0.65%	0.00%	10.50%	0.01%
Trimble Inc	TRMB	0.05%	n/a	n/a	14.50%	0.01%
Anthem Inc	ANTM	0.24%	1.52%	0.00%	14.00%	0.03%
CME Group Inc	CME	0.21%	1.87%	0.00%	2.50%	0.01%
Juniper Networks Inc	JNPR	0.03%	3.28%	0.00%	5.50%	0.00%
BlackRock Inc	BLK	0.35%	2.36%	0.01%	9.50%	0.03%
DTE Energy Co	DTE	0.07%	3.66%	0.00%	6.00%	0.00%
Celanese Corp	CE	0.05%	2.23%	0.00%	5.50%	0.00%
Nasdaq Inc	NDAQ	0.07%	1.45%	0.00%	7.00%	0.01%
Philip Morris International Inc	PM	0.40%	6.03%	0.02%	5.00%	0.02%
Ingersoll Rand Inc	IR	0.00%	n/a	n/a	n/a	n/a
salesforce.com Inc	CRM	0.67%	n/a	n/a	46.50%	0.31%
Huntington Ingalls Industries Inc	HII	0.02%	2.90%	0.00%	7.00%	0.00%
MetLife Inc	MET	0.14%	3.82%	0.01%	6.50%	0.01%
Under Armour Inc	UA	0.00%	n/a	n/a	n/a	n/a
Tapestry Inc	TPR	0.03%	n/a	n/a	4.00%	0.00%
CSX Corp	CSX	0.21%	1.21%	0.00%	9.00%	0.02%
Edwards Lifesciences Corp	EW	0.17%	n/a	n/a	13.50%	0.02%
Ameriprise Financial Inc	AMP	0.08%	2.10%	0.00%	12.00%	0.01%
Zebra Technologies Corp	ZBRA	0.07%	n/a	n/a	11.00%	0.01%
TechnipFMC PLC	FTI	0.00%	1.63%	0.00%	n/a	n/a
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.62%	0.00%	6.00%	0.01%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	7.50%	0.00%
Mastercard Inc	MA	1.01%	0.56%	0.01%	12.00%	0.12%
CarMax Inc	KMX	0.06%	n/a	n/a	8.50%	0.01%
Intercontinental Exchange Inc	ICE	0.20%	1.09%	0.00%	9.50%	0.02%
Fidelity National Information Services Inc	FIS	0.25%	1.13%	0.00%	28.00%	0.07%
Chipotle Mexican Grill Inc	CMG	0.13%	n/a	n/a	15.50%	0.02%
Wynn Resorts Ltd	WYNN	0.03%	n/a	n/a	27.00%	0.01%
Live Nation Entertainment Inc	LYV	0.00%	n/a	n/a	n/a	n/a
Assurant Inc	AIZ	0.03%	1.95%	0.00%	11.50%	0.00%
NRG Energy Inc	NRG	0.03%	3.14%	0.00%	-1.50%	0.00%
Monster Beverage Corp	MNST	0.15%	n/a	n/a	12.50%	0.02%
Regions Financial Corp	RF	0.05%	3.64%	0.00%	8.50%	0.00%
Mosaic Co/The	MOS	0.03%	0.77%	0.00%	21.00%	0.01%
Expedia Group Inc	EXPE	0.05%	n/a	n/a	12.00%	0.01%
Evergy Inc	EVERG	0.04%	3.98%	0.00%	7.50%	0.00%
Discovery Inc	DISCA	0.02%	n/a	n/a	15.50%	0.00%
CF Industries Holdings Inc	CF	0.03%	2.90%	0.00%	24.00%	0.01%
Leidos Holdings Inc	LDOS	0.05%	1.28%	0.00%	10.50%	0.01%
Alphabet Inc	GOOG	1.97%	n/a	n/a	14.50%	0.28%
TE Connectivity Ltd	TEL	0.13%	1.59%	0.00%	5.50%	0.01%
Cooper Cos Inc/The	COO	0.06%	0.02%	0.00%	14.50%	0.01%
Discover Financial Services	DFS	0.08%	2.11%	0.00%	5.50%	0.00%

STANDARD AND POOR'S 500 INDEX

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Name	Ticker	Weight in Index	Current Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Visa Inc	V	1.06%	0.66%	0.01%	15.00%	0.16%
Mid-America Apartment Communities Inc	MAA	0.05%	3.09%	0.00%	1.00%	0.00%
Xylem Inc/NY	XYL	0.06%	1.08%	0.00%	8.50%	0.00%
Marathon Petroleum Corp	MPX	0.09%	5.38%	0.00%	3.00%	0.00%
Advanced Micro Devices Inc	AMD	0.34%	n/a	n/a	27.00%	0.09%
Tractor Supply Co	TSCO	0.05%	1.47%	0.00%	10.50%	0.01%
ResMed Inc	RMD	0.10%	0.77%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	0.09%	n/a	n/a	11.00%	0.01%
Copart Inc	CPRT	0.08%	n/a	n/a	12.00%	0.01%
Fortinet Inc	FTNT	0.08%	n/a	n/a	21.00%	0.02%
Albemarle Corp	ALB	0.06%	0.95%	0.00%	4.00%	0.00%
Apache Corp	APA	0.02%	0.70%	0.00%	8.50%	0.00%
Essex Property Trust Inc	ESS	0.05%	3.47%	0.00%	1.00%	0.00%
Realty Income Corp	O	0.07%	4.76%	0.00%	6.50%	0.00%
Seagate Technology PLC	STX	0.05%	4.05%	0.00%	4.00%	0.00%
Westrock Co	WRK	0.04%	1.93%	0.00%	6.50%	0.00%
IHS Markit Ltd	INFO	0.11%	0.92%	0.00%	12.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	0.05%	0.65%	0.00%	10.50%	0.00%
Pool Corp	POOL	0.05%	0.66%	0.00%	17.50%	0.01%
Western Digital Corp	WDC	0.06%	n/a	n/a	1.00%	0.00%
PepsiCo Inc	PEP	0.61%	2.99%	0.02%	6.00%	0.04%
Diamondback Energy Inc	FANG	0.03%	2.65%	0.00%	0.50%	0.00%
Maxim Integrated Products Inc	MXIM	0.08%	n/a	n/a	7.00%	0.01%
ServiceNow Inc	NOW	0.34%	n/a	n/a	46.00%	0.16%
Church & Dwight Co Inc	CHD	0.07%	1.20%	0.00%	8.50%	0.01%
Duke Realty Corp	DRE	0.05%	2.58%	0.00%	-3.00%	0.00%
Federal Realty Investment Trust	FRT	0.02%	4.84%	0.00%	-0.50%	0.00%
MGM Resorts International	MGM	0.05%	0.04%	0.00%	25.00%	0.01%
American Electric Power Co Inc	AEP	0.13%	3.66%	0.00%	6.00%	0.01%
Vontier Corp	VNT	0.00%	n/a	n/a	n/a	n/a
JB Hunt Transport Services Inc	JBHT	0.05%	0.83%	0.00%	6.50%	0.00%
Lam Research Corp	LRCX	0.22%	1.07%	0.00%	12.50%	0.03%
Mohawk Industries Inc	MHK	0.03%	n/a	n/a	-1.50%	0.00%
Pentair PLC	PNR	0.03%	1.47%	0.00%	5.50%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.19%	n/a	n/a	32.00%	0.06%
Amcor PLC	AMCR	0.00%	4.30%	0.00%	n/a	n/a
Facebook Inc	FB	2.02%	n/a	n/a	15.50%	0.31%
T-Mobile US Inc	TMUS	0.51%	n/a	n/a	9.50%	0.05%
United Rentals Inc	URI	0.06%	n/a	n/a	7.00%	0.00%
Alexandria Real Estate Equities Inc	ARE	0.08%	2.61%	0.00%	14.50%	0.01%
ABIOMED Inc	ABMD	0.05%	n/a	n/a	9.50%	0.00%
Delta Air Lines Inc	DAL	0.08%	n/a	n/a	5.00%	0.00%
United Airlines Holdings Inc	UAL	0.04%	n/a	n/a	2.00%	0.00%
News Corp	NWS	0.00%	1.06%	0.00%	n/a	n/a
Centene Corp	CNC	0.11%	n/a	n/a	13.00%	0.01%
Martin Marietta Materials Inc	MLM	0.06%	0.79%	0.00%	8.50%	0.00%
Teradyne Inc	TER	0.06%	0.35%	0.00%	14.50%	0.01%
PayPal Holdings Inc	PYPL	0.89%	n/a	n/a	19.00%	0.17%
Tesla Inc	TSLA	0.00%	n/a	n/a	n/a	n/a
DISH Network Corp	DISH	0.03%	n/a	n/a	3.00%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.11%	n/a	n/a	19.50%	0.02%
Dow Inc	DOW	0.00%	5.39%	0.00%	n/a	n/a
Everest Re Group Ltd	RE	0.03%	2.94%	0.00%	10.50%	0.00%
Teledyne Technologies Inc	TDY	0.04%	n/a	n/a	8.00%	0.00%
News Corp	NWSA	0.00%	1.03%	0.00%	n/a	n/a
Exelon Corp	EXC	0.13%	3.68%	0.00%	3.50%	0.00%
Global Payments Inc	GPX	0.17%	0.44%	0.00%	11.50%	0.02%
Crown Castle International Corp	CCI	0.22%	3.34%	0.01%	12.50%	0.03%
Aptiv PLC	APTIV	0.12%	n/a	n/a	9.50%	0.01%
Advance Auto Parts Inc	AAP	0.03%	0.67%	0.00%	11.00%	0.00%
Align Technology Inc	ALGN	0.13%	n/a	n/a	17.00%	0.02%
Illumina Inc	ILMN	0.20%	n/a	n/a	9.50%	0.02%
LKQ Corp	LKQ	0.03%	n/a	n/a	10.00%	0.00%
Nielsen Holdings PLC	NLSN	0.00%	1.07%	0.00%	n/a	n/a
Garmin Ltd	GRMN	0.07%	2.12%	0.00%	10.50%	0.01%
Zoetis Inc	ZTS	0.24%	0.65%	0.00%	12.00%	0.03%
Digital Realty Trust Inc	DLR	0.13%	3.11%	0.00%	7.00%	0.01%
Equinix Inc	EQIX	0.21%	1.44%	0.00%	14.50%	0.03%
Las Vegas Sands Corp	LVS	0.12%	n/a	n/a	5.50%	0.01%
Discovery Inc	DISCK	0.00%	n/a	n/a	n/a	n/a

Notes:

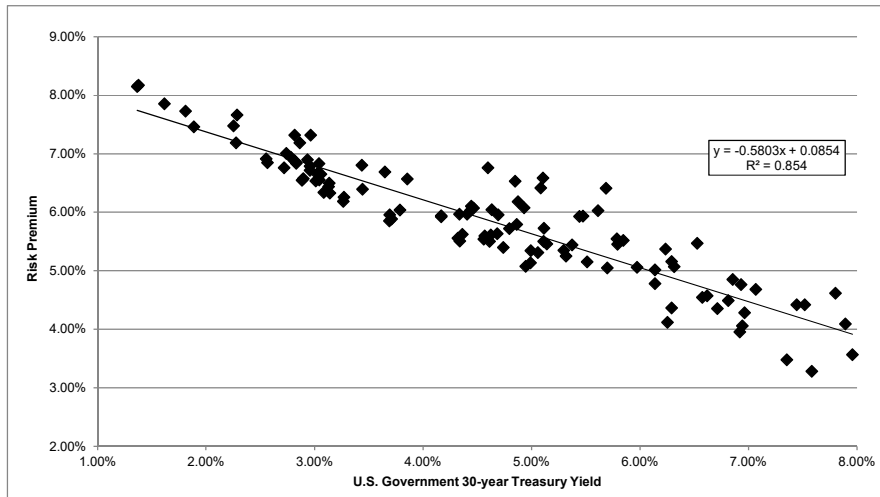
- [1] Equals Sum ([6])
[2] Equals Sum ([8])
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Equals weight in S&P 500 based on market capitalization
[5] Source: Bloomberg Professional
[6] Equals [4] x [5]
[7] Source: Value Line

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Gas ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.42%	7.80%	4.62%
1992.2	11.98%	7.89%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.66%
2019.4	9.73%	2.25%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.47%	1.62%	7.86%
2021.1	9.54%	1.81%	7.73%
AVERAGE	10.48%	4.63%	5.84%
MEDIAN	10.37%	4.63%	5.93%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.924122
R Square	0.854001
Adjusted R Square	0.852686
Standard Error	0.003917
Observations	113

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.009961	0.009961	649.280952	0.000000
Residual	111	0.001703	0.000015		
Total	112	0.011664			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.0854	0.0011120	76.75	0.000000	0.083147	0.087554	0.083147	0.087554
U.S. Govt. 30-year Treasury	(0.5803)	0.0227731	(25.48)	0.000000	(0.625409)	(0.535156)	(0.625409)	(0.535156)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	1.77%	7.51%	9.28%
Blue Chip Consensus Forecast (Q2 2021 - Q2 2022) [5]	2.06%	7.34%	9.40%
Blue Chip Consensus Forecast (2022-2026) [6]	2.80%	6.91%	9.71%
AVERAGE			9.46%

Notes:

- [1] Source: Regulatory Research Associates, rate cases through January 31, 2021
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] - Column [2]
[4] Source: Bloomberg Professional, 30-day average as of January 31, 2021
[5] Source: Blue Chip Financial Forecasts, Vol. 40, No. 2, February 1, 2021, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.084369 + (-0.562291 x Column [7])
[9] Equals Column [7] + Column [8]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1]	[2]
		Market Capitalization (\$ billions)	Market-to-Book Ratio
Atmos Energy Corporation	ATO	11.48	1.62
NiSource Inc.	NI	8.51	1.78
Northwest Natural Gas Company	NWN	1.37	1.60
ONE Gas Inc.	OGS	3.92	1.78
South Jersey Industries, Inc.	SJI	2.20	1.35
Southwest Gas Corporation	SWX	3.39	1.29
Spire, Inc.	SR	3.21	1.38
Average		4.87	1.54
Median		3.39	1.60

Michigan Gas Utilities		
Rate Base (\$ millions) [3]	\$	324.53
Common Equity Ratio [3]		52.50%
Implied Common Equity (\$ millions) [4]	\$	170.38
Implied Market Capitalization (\$ millions) [5]	\$	273.43
As a percent of Proxy Group Median Market Capitalization		8.06%

Duff & Phelps Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10	[6]	[7]
	Market Capitalization of Largest Company (\$ millions)	Size Premium
1-Largest	1,061,355.01	-0.27%
2	30,542.94	0.48%
3	13,100.23	0.69%
4	6,614.96	0.77%
5	4,311.25	1.08%
6	2,685.87	1.37%
7	1,668.28	1.47%
8	993.85	1.61%
9	515.60	2.26%
10-Smallest	229.75	4.99%
Michigan Gas Utilities - Implied Market Capitalization	273.43	2.26%
Proxy Group Median Market Capitalization	3,391.46	1.08%
Size Premium [8]		1.18%

Notes:

[1] Source: Bloomberg LP; equals 30-day average as of January 29, 2021

[2] Source: Bloomberg LP; equals 30-day average as of January 29, 2021

[3] Data provided by Michigan Gas Utilities.

[4] Equals projected rate base x projected common equity ratio

[5] Equals [4] x proxy group median market-to-book ratio

[6] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019

[7] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2019

[8] Equals 2.26% - 1.08%

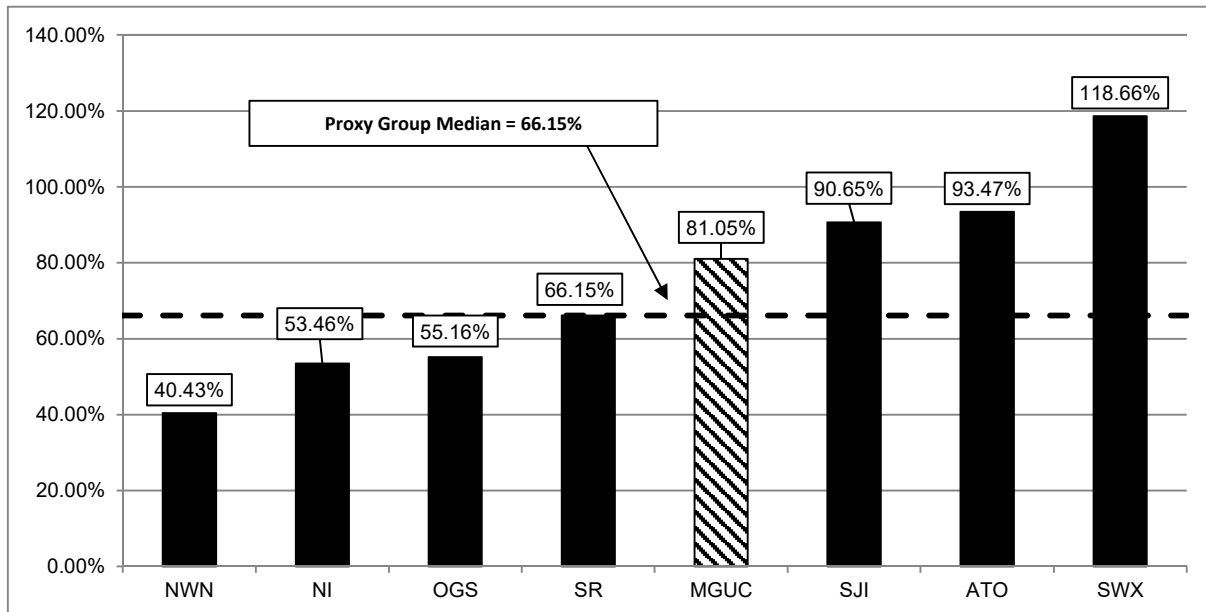
2021-2025 CAPITAL EXPENDITURES AS A PERCENT OF 2019 NET PLANT
(\$ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2019	2021	2022	2023	2024	2025	2021-25 Cap. Ex. / 2019 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			\$16.15	\$15.83	\$15.50	\$15.50	\$15.50	
Common Shares Outstanding			130.00	137.50	145.00	145.00	145.00	
Capital Expenditures			\$2,099.5	\$2,175.9	\$2,247.5	\$2,247.5	\$2,247.5	93.47%
Net Plant		\$11,788.0						
NiSource Inc.	NI							
Capital Spending per Share			\$4.70	\$4.70	\$4.70	\$4.70	\$4.70	
Common Shares Outstanding			384.00	384.50	385.00	385.00	385.00	
Capital Expenditures			\$1,804.8	\$1,807.2	\$1,809.5	\$1,809.5	\$1,809.5	53.46%
Net Plant		\$16,912.0						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			\$6.15	\$6.20	\$6.25	\$6.25	\$6.25	
Common Shares Outstanding			31.00	31.50	32.00	32.00	32.00	
Capital Expenditures			\$190.7	\$195.3	\$200.0	\$200.0	\$200.0	40.43%
Net Plant		\$2,438.9						
ONE Gas Inc.	OGS							
Capital Spending per Share			\$8.95	\$9.15	\$9.35	\$9.35	\$9.35	
Common Shares Outstanding			53.50	54.25	55.00	55.00	55.00	
Capital Expenditures			\$478.8	\$496.4	\$514.3	\$514.3	\$514.3	55.16%
Net Plant		\$4,565.2						
South Jersey Industries, Inc.	SJI							
Capital Spending per Share			\$5.85	\$6.55	\$7.25	\$7.25	\$7.25	
Common Shares Outstanding			103.00	106.50	110.00	110.00	110.00	
Capital Expenditures			\$602.6	\$697.6	\$797.5	\$797.5	\$797.5	90.65%
Net Plant		\$4,073.5						
Southwest Gas Corporation	SWX							
Capital Spending per Share			\$16.95	\$20.03	\$23.10	\$23.10	\$23.10	
Common Shares Outstanding			59.00	62.00	65.00	65.00	65.00	
Capital Expenditures			\$1,000.1	\$1,241.6	\$1,501.5	\$1,501.5	\$1,501.5	118.66%
Net Plant		\$5,685.2						
Spire, Inc.	SR							
Capital Spending per Share			\$11.25	\$10.80	\$10.35	\$10.35	\$10.35	
Common Shares Outstanding			52.50	53.75	55.00	55.00	55.00	
Capital Expenditures			\$590.6	\$580.5	\$569.3	\$569.3	\$569.3	66.15%
Net Plant		\$4,352.0						
Michigan Gas Utilities	MGUC							
Capital Expenditures [8]					235.18			81.05%
Net Plant [9]		\$290.2						
Michigan Gas Utilities CapEx Total (2021 - 2025)								\$235.18
Michigan Gas Utilities CapEx Annual Average								\$47.0
Proxy Group Median								66.15%
Ratio of MGUC to the Proxy Group Median								1.23

Notes:

[1] - [6] Source: Value Line, dated November 27, 2020
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Data provided by Michigan Gas Utilities
[9] MGUC 2019 Annual Report, pp. 110

2021-2025 CAPITAL EXPENDITURES AS A PERCENT OF 2019 NET PLANT



Projected CAPEX / 2019 Net Plant

Company		2021-2025
Northwest Natural Gas Company	NWN	40.43%
NiSource Inc.	NI	53.46%
ONE Gas Inc.	OGS	55.16%
Spire, Inc.	SR	66.15%
Michigan Gas Utilities	MGUC	81.05%
South Jersey Industries, Inc.	SJ	90.65%
Atmos Energy Corporation	ATO	93.47%
Southwest Gas Corporation	SWX	118.66%
Proxy Group Median		66.15%
Michigan Gas Utilities/Proxy Group		1.23

Notes:

Source: Schedule D12, page 1, col. [7]

**COMPARISON OF MICHIGAN GAS UTILITIES AND PROXY GROUP COMPANIES
RISK ASSESSMENT**

		[1]		[2]		[3]
Company	Jurisdiction/Service	Test Year	Rate Base	Capital Cost Recovery Mechanism		
Atmos Energy Corporation	Kansas - Gas	Historical	Year End		Yes	
	Kentucky - Gas	Fully Forecast	Average		Yes	
	Louisiana - Gas	Historical	Year End		Yes	
	Mississippi - Gas	Partially Forecast	Average		Yes	
	Tennessee - Gas	Fully Forecast	Average		No	
	Texas - Gas	Historical	Year End		Yes	
NiSource Inc.	Indiana - Electric	Fully Forecast	Year End		Yes	
	Indiana - Gas	Fully Forecast	Year End		Yes	
	Kentucky - Gas	Fully Forecast	Average		Yes	
	Maryland - Gas	Partially Forecast	Average		Yes	
	Ohio - Gas	Partially Forecast	Year End		Yes	
	Pennsylvania - Gas	Fully Forecast	Year End		Yes	
	Virginia - Gas	Historical	Average		Yes	
	Oregon - Gas	Fully Forecast	Average		No	
Northwest Natural Gas Company	Washington - Gas	Historical	Average		No	
ONE Gas, Inc.	Kansas - Gas	Historical	Year End		Yes	
	Oklahoma - Gas	Historical	Year End		No	
	Texas - Gas	Historical	Year End		Yes	
	New Jersey - Gas	Partially Forecast	Year End		Yes	
South Jersey Industries, Inc.	Arizona - Gas	Historical	Year End		Yes	
Southwest Gas Corporation	California - Gas	Fully Forecast	Average		No	
	Nevada - Gas	Historical	Year End		Yes	
	Alabama - Gas	Fully Forecast	Average		No	
Spire, Inc.	Missouri East - Gas	Historical	Year End		Yes	
	Missouri West - Gas	Historical	Year End		Yes	
Proxy Group Totals	Fully Forecast	9	Year End	15	Yes	19
	Partially Forecast	4	Average	10	No	6
	Historical	12				
	Forecast	52.00%	Year End	60.00%	CCRM	76.00%
Michigan Gas Utilities [4]	Michigan	Fully Forecast	Average		Proposed	

Notes

[1] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 1/31/21

[2] Source: S&P Global - Market Intelligence Rate Case History (Past Rate Cases), accessed 1/31/21

[3] Source: "Adjustment Clauses: A State-by-state Overview," Regulatory Research Associates, November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.

[4] Data provided by Michigan Gas Utilities

FLOTATION COST ADJUSTMENT

Company	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense (\$000) [iii]	Net Proceeds Per Share	Total Flotation Costs (\$000)	Gross Equity Issue Before Costs (\$000)	Net Proceeds (\$000)	Flotation Cost Percentage
Integrus Holding, Inc.	11/12/2003	4,025	\$ 43.00	1.51	\$ 217	\$ 41.44	\$ 6,295	\$ 173,075	\$ 166,780	3.64%
Integrus Holding, Inc.	11/9/2005	1,900	\$ 53.70	1.75	\$ 415	\$ 51.73	\$ 3,740	\$ 102,030	\$ 98,291	3.67%
							\$ 10,035	\$ 275,105	\$ 265,070	3.65%

Notes:

[i] Offering Completion Date

[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

[iii] 2005 SEC Form 10-K, at 60 and 2003 SEC Form 10-K, at 73 (Net Proceeds).

The flotation cost adjustment is derived by dividing the dividend yield by $1 + F$ (where F = flotation costs expressed in percentage terms), or by 0.9635, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
						Expected Dividend Yield						
		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
Company	Ticker											
Atmos Energy Corporation	ATO	\$2.50	\$91.58	2.73%	2.82%	2.93%	7.00%	6.77%	7.10%	6.96%	9.78%	9.89%
NiSource Inc.	NI	\$0.84	\$22.20	3.78%	3.91%	4.06%	13.00%	1.65%	5.60%	6.75%	10.66%	10.81%
Northwest Natural Gas Company	NWN	\$1.92	\$45.33	4.24%	4.32%	4.49%	5.97%	3.10%	3.10%	4.06%	8.38%	8.54%
ONE Gas Inc.	OGS	\$2.16	\$74.39	2.90%	2.99%	3.10%	6.50%	5.00%	6.00%	5.83%	8.82%	8.93%
South Jersey Industries, Inc.	SJI	\$1.21	\$21.93	5.52%	6.08%	6.31%	12.50%	24.50%	24.50%	20.50%	26.58%	26.81%
Southwest Gas Corporation	SWX	\$2.28	\$59.91	3.81%	3.92%	4.07%	9.00%	4.00%	5.00%	6.00%	9.92%	10.07%
Spire, Inc.	SR	\$2.60	\$62.37	4.17%	4.36%	4.52%	5.50%	5.37%	16.50%	9.12%	13.48%	13.65%
Median											9.92%	10.07%
Flotation Cost Adjustment											[12]	0.15%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 30-day average as of January 31, 2021

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [9])

[5] Equals [4] / (1 - Flotation Cost)

[6] Source: Value Line

[7] Source: Yahoo! Finance

[8] Source: Zacks

[9] Equals Average ([6], [7], [8])

[10] Equals [4] + [9]

[11] Equals [5] + [9]

[12] Equals Median ([11]) - Median ([10])

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	58.43%	59.20%	58.43%
NiSource Inc.	NI	54.33%	54.83%	54.33%
Northwest Natural Gas Company	NWN	49.19%	49.33%	49.19%
One Gas Inc.	OGS	63.38%	62.03%	63.38%
South Jersey Industries, Inc	SJI	52.88%	52.82%	52.88%
Southwest Gas Corporator	SWX	48.52%	49.38%	48.52%
Spire Inc.	SR	60.72%	62.79%	60.72%
Proxy Group				
MEAN		55.35%	55.77%	55.35%
LOW		48.52%	49.33%	48.52%
HIGH		63.38%	62.79%	63.38%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	58.43%	59.20%	58.43%
Columbia Gas of Kentucky, Inc	NI	54.23%	54.62%	54.23%
Columbia Gas of Maryland, Inc	NI	52.38%	56.70%	52.38%
Columbia Gas of Ohio, Inc	NI	53.00%	54.40%	53.00%
Columbia Gas of Pennsylvania, Inc	NI	55.59%	55.68%	55.59%
Columbia Gas of Virginia, Inc	NI	42.53%	42.71%	42.53%
Northern Indiana Public Service Company LLC	NI	56.43%	56.37%	56.43%
Northwest Natural Gas Company	NWN	49.19%	49.33%	49.19%
Kansas Gas Service Company, Inc	OGS	63.55%	62.20%	63.55%
Oklahoma Natural Gas Company	OGS		61.94%	61.94%
Texas Gas Service Company, Inc	OGS	63.23%	61.95%	63.23%
South Jersey Gas Company	SJI	52.88%	52.82%	52.88%
Southwest Gas Corporator	SWX	48.52%	49.38%	48.52%
Spire Alabama Inc.	SR	66.82%	71.48%	66.82%
Spire Gulf Inc.	SR	37.18%	45.31%	37.18%
Spire Mississippi Inc	SR		100.00%	100.00%
Spire Missouri Inc	SR	59.05%	58.91%	59.05%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating

[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	41.57%	40.80%	41.57%
NiSource Inc.	NI	45.67%	45.17%	45.67%
Northwest Natural Gas Company	NWN	50.81%	50.67%	50.81%
One Gas Inc.	OGS	36.62%	37.97%	36.62%
South Jersey Industries, Inc.	SJI	47.12%	47.18%	47.12%
Southwest Gas Corporation	SWX	51.48%	50.62%	51.48%
Spire Inc.	SR	39.28%	37.21%	39.28%
Proxy Group				
MEAN		44.65%	44.23%	44.65%
LOW		36.62%	37.21%	36.62%
HIGH		51.48%	50.67%	51.48%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	41.57%	40.80%	41.57%
Columbia Gas of Kentucky, Inc	NI	45.77%	45.38%	45.77%
Columbia Gas of Maryland, Inc	NI	47.62%	43.30%	47.62%
Columbia Gas of Ohio, Inc	NI	47.00%	45.60%	47.00%
Columbia Gas of Pennsylvania, Inc	NI	44.41%	44.32%	44.41%
Columbia Gas of Virginia, Inc	NI	57.47%	57.29%	57.47%
Northern Indiana Public Service Company LLC	NI	43.57%	43.63%	43.57%
Northwest Natural Gas Company	NWN	50.81%	50.67%	50.81%
Kansas Gas Service Company, Inc	OGS	36.45%	37.80%	36.45%
Oklahoma Natural Gas Company	OGS		38.06%	38.06%
Texas Gas Service Company, Inc	OGS	36.77%	38.05%	36.77%
South Jersey Gas Company	SJI	47.12%	47.18%	47.12%
Southwest Gas Corporation	SWX	51.48%	50.62%	51.48%
Spire Alabama Inc.	SR	33.18%	28.52%	33.18%
Spire Gulf Inc.	SR	62.82%	54.69%	62.82%
Spire Mississippi Inc	SR		0.00%	0.00%
Spire Missouri Inc	SR	40.95%	41.09%	40.95%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating Subsidiaries.

[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%
South Jersey Industries, Inc.	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%
Proxy Group				
MEAN		0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2019	2018	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc	NI	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc	NI	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc	NI	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc	NI	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc	NI	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc	OGS	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%
Texas Gas Service Company, Inc	OGS	0.00%	0.00%	0.00%
South Jersey Gas Company	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporatior	SWX	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%
Spire Mississippi Inc	SR		0.00%	0.00%
Spire Missouri Inc	SR	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, and long-term debt of Operating

[2] Natural Gas operating subsidiaries where data was unable to be obtained for 2018 and 2019 were remove from the analysis.

Schedule E1

Michigan Public Service Commission
Michigan Gas Utilities
Market Outlook: 5-Year Annual Calendar Gas Forecast by Class
Units in MMcf

Case No.: U-20718
Exhibit No.: A-15
Schedule: E1
Page: 1 of 1
Witness: Jared J. Peccarelli

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line									
No.	<u>Year</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>Other</u>	<u>Total</u>	<u>Losses and CU</u>	<u>% of Output</u>	<u>System Output</u>
1	2021	13,862	6,643	13,700	-	34,205	37	0.1071%	34,242
2	2022	13,637	6,579	13,421	-	33,637	(62)	-0.1834%	33,575
3	2023	13,572	6,627	13,421	-	33,620	(62)	-0.1834%	33,558
4	2024	13,513	6,676	13,421	-	33,609	(62)	-0.1834%	33,547
5	2025	13,397	6,720	13,421	-	33,538	(62)	-0.1834%	33,476

Note: EUT volumes added to Industrial Class

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Line Description	Total MGU Natural Gas	Total GS Residential	Total GS Small Commercial	Total GS Large Commercial	Total Transport	Total Special Contract
1	Development of Rate Base						
2	Net Plant						
3	Utility Plant in Service	614,691,824	383,200,821	83,198,922	6,036,032	141,143,955	1,112,093
4	Construction Work in Progress	6,778,850	4,309,779	892,522	71,092	1,491,650	13,807
5	Accumulated Depreciation	(254,172,180)	(161,887,213)	(32,142,362)	(2,378,711)	(57,300,610)	(463,284)
6	Net Plant	367,298,494	225,623,386	51,949,082	3,728,414	85,334,995	662,617
7	Other Rate Base Components						
8	Gas Stored Underground	7,424,791	4,280,190	1,828,128	250,282	1,040,551	25,640
9	Material and Supplies	1,092,712	730,643	133,087	6,378	220,904	1,700
10	Prepayments	52,725	31,781	7,687	594	12,557	106
11	Cash & Bank Balances	1,968,086	852,953	348,916	39,135	717,053	10,029
12	Working Capital	23,051,441	10,124,130	4,182,523	493,171	8,145,705	105,912
13	Other Rate Base Components	33,589,756	16,019,698	6,500,341	789,560	10,136,771	143,386
14	Total Rate Base						
15	Total Rate Base	400,888,250	241,643,084	58,449,423	4,517,974	95,471,766	806,003
16	Operating Income						
17	Operating Revenues						
18	Sales Revenue	141,029,474	85,644,158	32,905,083	4,428,247	17,954,822	97,164
19	Other Operating Revenues	1,130,765	691,691	176,858	14,642	246,356	1,218
20	Other Misc Revenues	0	0	0	0	0	0
21	Operating Revenues	142,160,240	86,335,850	33,081,940	4,442,889	18,201,178	98,382
22	Operating Expenses						
23	Operation & Maintenance	100,277,695	65,461,615	23,682,324	3,508,237	7,571,259	54,261
24	Book Depreciation Expense	19,225,123	12,587,017	2,450,841	152,048	4,004,625	30,593
25	Taxes Other than Income Taxes	7,474,961	4,554,022	1,076,034	81,907	1,748,389	14,608
26	State Income Taxes	(775,137)	(467,229)	(113,015)	(8,736)	(184,599)	(1,558)
27	Federal Income Taxes	(1,950,743)	(1,175,848)	(284,418)	(21,985)	(464,571)	(3,922)
28	Deferred Income Taxes	3,721,155	2,242,997	542,544	41,937	886,195	7,482
29	Regulatory Debits and Credits	2,500,000	1,506,923	364,499	28,175	595,376	5,026
30	Investment Tax Credits	(18,172)	(10,954)	(2,650)	(205)	(4,328)	(37)
31	Operating Expenses	130,454,882	84,698,544	27,716,159	3,781,379	14,152,347	106,453
32	Revenue Deficiency						
33	Revenue Deficiency at Present Rates						
34	Adjustments to Operating Income	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	1,637,306	5,365,781	661,511	4,048,831	(8,071)
36	Earned Rate Of Return	0.0292	0.0068	0.0918	0.1464	0.0424	(0.0100)
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	0.0504	(0.0346)	(0.0892)	0.0148	0.0672
39	Income Deficiency (Sufficiency) \$	11,233,708	12,189,656	(2,021,270)	(402,989)	1,414,120	54,191
40	Tax Gross-up Factor	0.3466					
41	Additional Taxes on Income Deficiency	3,893,828	2,347,079	567,719	43,883	927,317	7,829
42	Revenue Deficiency (Sufficiency) \$	15,127,536	14,536,736	(1,453,551)	(359,106)	2,341,438	62,020
43	Revenue Deficiency (Sufficiency) %	0.1073	0.1697	(0.0442)	(0.0811)	0.1304	0.6383
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	14,536,736	(1,453,551)	(359,106)	2,341,438	62,020
46	Revenue Deficiency After Specified Adjustments %	0.1073	0.1697	(0.0442)	(0.0811)	0.1304	0.6383
47	Adjustments to Requested Revenue	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	14,536,736	(1,453,551)	(359,106)	2,341,438	62,020
49	Revenue Deficiency For 2021 Rate Design %	0.1073	0.1697	(0.0442)	(0.0811)	0.1304	0.6383
50	Sales Revenue	141,029,474	85,644,158	32,905,083	4,428,247	17,954,822	97,164
51	Revenue Requirement	156,157,011	100,180,894	31,451,532	4,069,141	20,296,260	159,184
52	Cost of Gas	65,313,503	42,853,300	19,255,797	3,203,346	0	1,059
53	Revenue Requirement excl Gas Costs	90,843,508	57,327,594	12,195,734	865,795	20,296,260	158,125

Source: Exhibit A-16 Schedule F1.2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Description	Total MGU Natural Gas	Residential			Small			Medium
			General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Development of Rate Base								
2	Net Plant								
3	Utility Plant in Service	614,691,824	383,200,821	54,320,445	67,156	83,198,922	20,415,438	5,419,901	13,729,504
4	Construction Work in Progress	6,778,850	4,309,779	604,349	570	892,522	208,777	52,794	142,877
5	Accumulated Depreciation	(254,172,180)	(161,887,213)	(23,016,753)	(21,750)	(32,142,362)	(7,784,161)	(1,983,612)	(5,407,915)
6	Net Plant	367,298,494	225,623,386	31,908,041	45,976	51,949,082	12,840,054	3,489,083	8,464,467
7	Other Rate Base Components								
8	Gas Stored Underground	7,424,791	4,280,190	604,299	0	1,828,128	428,713	0	0
9	Material and Supplies	1,092,712	730,643	104,161	132	133,087	33,610	8,751	18,312
10	Prepayments	52,725	31,781	4,493	6	7,687	1,889	509	1,286
11	Cash & Bank Balances	1,968,086	852,953	120,541	172	348,916	81,741	31,641	107,877
12	Working Capital	23,051,441	10,124,130	1,421,288	1,859	4,182,523	973,281	342,312	1,183,116
13	Other Rate Base Components	33,589,756	16,019,698	2,254,782	2,169	6,500,341	1,519,234	383,214	1,310,591
14	Total Rate Base								
15	Total Rate Base	400,888,250	241,643,084	34,162,822	48,145	58,449,423	14,359,288	3,872,296	9,775,058
16	Operating Income								
17	Operating Revenues								
18	Sales Revenue	141,029,474	85,644,158	5,968,608	7,365	32,905,083	3,134,341	1,034,136	2,678,943
19	Other Operating Revenues	1,130,765	691,691	97,307	99	176,858	40,910	12,609	31,997
20	Other Misc Revenues	0	0	0	0	0	0	0	0
21	Operating Revenues	142,160,240	86,335,850	6,065,915	7,465	33,081,940	3,175,251	1,046,745	2,710,939
22	Operating Expenses								
23	Operation & Maintenance	100,277,695	65,461,615	3,150,652	13,235	23,682,324	1,026,614	625,441	790,994
24	Book Depreciation Expense	19,225,123	12,587,017	1,777,491	2,058	2,450,841	597,504	148,076	341,027
25	Taxes Other than Income Taxes	7,474,961	4,554,022	641,101	1,013	1,076,034	261,908	75,018	177,534
26	State Income Taxes	(775,137)	(467,229)	(66,055)	(93)	(113,015)	(27,764)	(7,487)	(18,901)
27	Federal Income Taxes	(1,950,743)	(1,175,848)	(166,238)	(234)	(284,418)	(69,873)	(18,843)	(47,566)
28	Deferred Income Taxes	3,721,155	2,242,997	317,109	447	542,544	133,287	35,944	90,735
29	Regulatory Debits and Credits	2,500,000	1,506,923	213,045	300	364,499	89,547	24,148	60,959
30	Investment Tax Credits	(18,172)	(10,954)	(1,549)	(2)	(2,650)	(651)	(176)	(443)
31	Operating Expenses	130,454,882	84,698,544	5,865,556	16,724	27,716,159	2,010,571	882,121	1,394,340
32	Revenue Deficiency								
33	Revenue Deficiency at Present Rates								
34	Adjustments to Operating Income	0	0	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	1,637,306	200,359	(9,259)	5,365,781	1,164,680	164,624	1,316,600
36	Earned Rate Of Return	0.0292	0.0068	0.0059	(0.1923)	0.0918	0.0811	0.0425	0.1347
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	0.0504	0.0514	0.2495	(0.0346)	(0.0239)	0.0147	(0.0775)
39	Income Deficiency (Sufficiency) \$	11,233,708	12,189,656	1,754,458	12,014	(2,021,270)	(343,033)	56,951	(757,265)
40	Tax Gross-up Factor	0.3466							
41	Additional Taxes on Income Deficiency	3,893,828	2,347,079	331,824	468	567,719	139,472	37,612	94,945
42	Revenue Deficiency (Sufficiency) \$	15,127,536	14,536,736	2,086,282	12,482	(1,453,551)	(203,561)	94,563	(662,320)
43	Revenue Deficiency (Sufficiency) %	0.1073	0.1697	0.3495	1.6946	(0.0442)	(0.0649)	0.0914	(0.2472)
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	14,536,736	2,086,282	12,482	(1,453,551)	(203,561)	94,563	(662,320)
46	Revenue Deficiency After Specified Adjustments %	0.1073	0.1697	0.3495	1.6946	(0.0442)	(0.0649)	0.0914	(0.2472)
47	Adjustments to Requested Revenue	0	0	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	14,536,736	2,086,282	12,482	(1,453,551)	(203,561)	94,563	(662,320)
49	Revenue Deficiency For 2021 Rate Design %	0.1073	0.1697	0.3495	1.6946	(0.0442)	(0.0649)	0.0914	(0.2472)
50	Sales Revenue	141,029,474	85,644,158	5,968,608	7,365	32,905,083	3,134,341	1,034,136	2,678,943
51	Revenue Requirement	156,157,011	100,180,894	8,054,889	19,847	31,451,532	2,930,780	1,128,698	2,016,623
52	Cost of Gas	65,313,503	42,853,300	0	0	19,255,797	0	0	0
53	Revenue Requirement excl Gas Costs	90,843,508	57,327,594	8,054,889	19,847	12,195,734	2,930,780	1,128,698	2,016,623

Source: Col. (B): Exhibit A-11 through A-14, Cols. (C) to (O): Workpaper ALN-2

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	Large				Super Large	Other
			General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	Development of Rate Base							
2	Net Plant							
3	Utility Plant in Service	614,691,824	6,036,032	32,538,061	218,514	193,726	14,241,210	1,112,093
4	Construction Work in Progress	6,778,850	71,092	330,461	2,454	2,114	147,255	13,807
5	Accumulated Depreciation	(254,172,180)	(2,378,711)	(13,162,240)	(82,604)	(76,825)	(5,764,750)	(463,284)
6	Net Plant	367,298,494	3,728,414	19,706,282	138,363	119,015	8,623,716	662,617
7	Other Rate Base Components							
8	Gas Stored Underground	7,424,791	250,282	0	7,540	0	0	25,640
9	Material and Supplies	1,092,712	6,378	39,182	277	265	16,214	1,700
10	Prepayments	52,725	594	3,008	22	18	1,326	106
11	Cash & Bank Balances	1,968,086	39,135	254,621	1,499	1,646	117,314	10,029
12	Working Capital	23,051,441	493,171	2,865,410	17,684	17,707	1,323,050	105,912
13	Other Rate Base Components	33,589,756	789,560	3,162,221	27,021	19,636	1,457,903	143,386
14	Total Rate Base							
15	Total Rate Base	400,888,250	4,517,974	22,868,503	165,385	138,650	10,081,619	806,003
16	Operating Income							
17	Operating Revenues							
18	Sales Revenue	141,029,474	4,428,247	3,757,984	37,089	38,688	1,297,670	97,164
19	Other Operating Revenues	1,130,765	14,642	46,223	450	462	16,299	1,218
20	Other Misc Revenues	0	0	0	0	0	0	0
21	Operating Revenues	142,160,240	4,442,889	3,804,207	37,539	39,150	1,313,969	98,382
22	Operating Expenses							
23	Operation & Maintenance	100,277,695	3,508,237	1,379,078	10,116	12,412	562,716	54,261
24	Book Depreciation Expense	19,225,123	152,048	795,710	5,375	4,756	332,628	30,593
25	Taxes Other than Income Taxes	7,474,961	81,907	407,641	2,954	2,537	178,684	14,608
26	State Income Taxes	(775,137)	(8,736)	(44,217)	(320)	(268)	(19,493)	(1,558)
27	Federal Income Taxes	(1,950,743)	(21,985)	(111,279)	(805)	(675)	(49,058)	(3,922)
28	Deferred Income Taxes	3,721,155	41,937	212,272	1,535	1,287	93,580	7,482
29	Regulatory Debits and Credits	2,500,000	28,175	142,611	1,031	865	62,871	5,026
30	Investment Tax Credits	(18,172)	(205)	(1,037)	(7)	(6)	(457)	(37)
31	Operating Expenses	130,454,882	3,781,379	2,780,779	19,879	20,907	1,161,471	106,453
32	Revenue Deficiency							
33	Revenue Deficiency at Present Rates							
34	Adjustments to Operating Income	0	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	661,511	1,023,428	17,659	18,243	152,497	(8,071)
36	Earned Rate Of Return	0.0292	0.1464	0.0448	0.1068	0.1316	0.0151	(0.0100)
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	(0.0892)	0.0125	(0.0496)	(0.0744)	0.0421	0.0672
39	Income Deficiency (Sufficiency) \$	11,233,708	(402,989)	285,122	(8,196)	(10,310)	424,379	54,191
40	Tax Gross-up Factor	0.3466						
41	Additional Taxes on Income Deficiency	3,893,828	43,883	222,122	1,606	1,347	97,923	7,829
42	Revenue Deficiency (Sufficiency) \$	15,127,536	(359,106)	507,243	(6,590)	(8,963)	522,302	62,020
43	Revenue Deficiency (Sufficiency) %	0.1073	(0.0811)	0.1350	(0.1777)	(0.2317)	0.4025	0.6383
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	(359,106)	507,243	(6,590)	(8,963)	522,302	62,020
46	Revenue Deficiency After Specified Adjustments %	0.1073	(0.0811)	0.1350	(0.1777)	(0.2317)	0.4025	0.6383
47	Adjustments to Requested Revenue	0	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	(359,106)	507,243	(6,590)	(8,963)	522,302	62,020
49	Revenue Deficiency For 2021 Rate Design %	0.1073	(0.0811)	0.1350	(0.1777)	(0.2317)	0.4025	0.6383
50	Sales Revenue	141,029,474	4,428,247	3,757,984	37,089	38,688	1,297,670	97,164
51	Revenue Requirement	156,157,011	4,069,141	4,265,227	30,499	29,725	1,819,971	159,184
52	Cost of Gas	65,313,503	3,203,346	0	0	0	0	1,059
53	Revenue Requirement excl Gas Costs	90,843,508	865,795	4,265,227	30,499	29,725	1,819,971	158,125

Source: Col. (B): Exhibit A-11 through A-14, Cols. (C) to (O): Workpaper ALN-2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Description	Total MGU Natural Gas	Residential			Small			Medium
			General Service- Residential	Customer Choice Residential	Agg Transport- Residential	General Service- Small	Customer Choice GS-Small	Agg Transport- GS-Small	Transport-TR-1
1	Units								
2	Throughput total	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168
3	Customers average	182,332	146,650	21,110	7	11,364	2,737	252	109
4	Commodity total	18,134,581	11,951,774	0	0	5,327,930	0	0	0
5									
6	Revenue Requirement								
7	Cost of Gas								
8	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	Commodity	\$65,313,503	\$42,853,300	\$0	\$0	\$19,255,797	\$0	\$0	\$0
11	Sub-total	\$65,313,503	\$42,853,300	\$0	\$0	\$19,255,797	\$0	\$0	\$0
12	Production								
13	Demand	\$1,326,966	\$575,097	\$81,274	\$116	\$235,254	\$55,113	\$21,334	\$72,735
14	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Commodity	\$1,145,077	\$754,674	\$0	\$0	\$336,423	\$0	\$0	\$0
16	Sub-total	\$2,472,043	\$1,329,771	\$81,274	\$116	\$571,677	\$55,113	\$21,334	\$72,735
17	Storage								
18	Demand	\$4,175,783	\$2,407,225	\$339,864	\$0	\$1,028,159	\$241,113	\$0	\$0
19	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	Sub-total	\$4,175,783	\$2,407,225	\$339,864	\$0	\$1,028,159	\$241,113	\$0	\$0
22	Transmission								
23	Demand	\$5,559,598	\$2,409,488	\$340,514	\$487	\$985,643	\$230,909	\$89,383	\$304,739
24	Customer	\$3,808,924	\$1,353,383	\$190,886	\$319	\$603,319	\$141,619	\$61,597	\$247,442
25	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
26	Sub-total	\$9,368,523	\$3,762,871	\$531,400	\$806	\$1,588,962	\$372,528	\$150,980	\$552,181
27	Distribution								
28	Demand	\$16,276,231	\$7,029,448	\$993,610	\$1,425	\$2,885,005	\$676,033	\$262,127	\$895,772
29	Customer	\$48,398,517	\$35,778,766	\$5,105,873	\$7,878	\$5,167,978	\$1,362,173	\$317,672	\$245,449
30	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	Sub-total	\$64,674,747	\$42,808,214	\$6,099,483	\$9,303	\$8,052,983	\$2,038,207	\$579,799	\$1,141,220
32	Customer								
33	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
34	Customer	\$10,152,412	\$7,019,513	\$1,002,868	\$9,622	\$953,954	\$223,818	\$376,586	\$250,486
35	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Sub-total	\$10,152,412	\$7,019,513	\$1,002,868	\$9,622	\$953,954	\$223,818	\$376,586	\$250,486
37	Grand Total								
38	Demand	\$27,338,578	\$12,421,258	\$1,755,263	\$2,028	\$5,134,061	\$1,203,169	\$372,843	\$1,273,246
39	Customer	\$62,359,853	\$44,151,661	\$6,299,626	\$17,819	\$6,725,251	\$1,727,611	\$755,855	\$743,377
40	Commodity	\$66,458,580	\$43,607,974	\$0	\$0	\$19,592,220	\$0	\$0	\$0
41	Sub-total	\$156,157,011	\$100,180,894	\$8,054,889	\$19,847	\$31,451,532	\$2,930,780	\$1,128,698	\$2,016,623

Source: Workpaper ALN-2

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	Large				Super Large	Other
			General Service-Large	Transport-TR-2	Customer Choice GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	Units							
2	Throughput total	33,636,752	854,602	6,659,678	21,109	26,200	3,126,872	275
3	Customers average	182,332	54	40	3	2	3	1
4	Commodity total	18,134,581	854,602	0	0	0	0	275
5								
6	Revenue Requirement							
7	Cost of Gas							
8	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	Commodity	\$65,313,503	\$3,203,346	\$0	\$0	\$0	\$0	\$1,059
11	Sub-total	\$65,313,503	\$3,203,346	\$0	\$0	\$0	\$0	\$1,059
12	Production							
13	Demand	\$1,326,966	\$26,386	\$171,676	\$1,010	\$1,110	\$79,098	\$6,762
14	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Commodity	\$1,145,077	\$53,962	\$0	\$0	\$0	\$0	\$17
16	Sub-total	\$2,472,043	\$80,349	\$171,676	\$1,010	\$1,110	\$79,098	\$6,779
17	Storage							
18	Demand	\$4,175,783	\$140,762	\$0	\$4,240	\$0	\$0	\$14,420
19	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	Sub-total	\$4,175,783	\$140,762	\$0	\$4,240	\$0	\$0	\$14,420
22	Transmission							
23	Demand	\$5,559,598	\$110,551	\$719,272	\$4,234	\$4,650	\$331,398	\$28,330
24	Customer	\$3,808,924	\$96,773	\$754,122	\$2,390	\$2,967	\$354,078	\$31
25	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
26	Sub-total	\$9,368,523	\$207,324	\$1,473,394	\$6,624	\$7,617	\$685,475	\$28,361
27	Distribution							
28	Demand	\$16,276,231	\$324,340	\$2,120,591	\$12,445	\$13,674	\$978,109	\$83,652
29	Customer	\$48,398,517	\$63,020	\$298,290	\$4,607	\$2,922	\$22,825	\$21,064
30	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	Sub-total	\$64,674,747	\$387,360	\$2,418,881	\$17,051	\$16,596	\$1,000,934	\$104,716
32	Customer							
33	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0
34	Customer	\$10,152,412	\$50,000	\$201,276	\$1,573	\$4,402	\$54,464	\$3,848
35	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Sub-total	\$10,152,412	\$50,000	\$201,276	\$1,573	\$4,402	\$54,464	\$3,848
37	Grand Total							
38	Demand	\$27,338,578	\$602,039	\$3,011,539	\$21,929	\$19,434	\$1,388,605	\$133,164
39	Customer	\$62,359,853	\$209,793	\$1,253,688	\$8,570	\$10,291	\$431,366	\$24,943
40	Commodity	\$66,458,580	\$3,257,308	\$0	\$0	\$0	\$0	\$1,077
41	Sub-total	\$156,157,011	\$4,069,141	\$4,265,227	\$30,499	\$29,725	\$1,819,971	\$159,184

Source: Workpaper ALN-2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Description	Total MGU Natural Gas	Residential			Small			Medium
			General Service- Residential	Customer Choice Residential	Agg Transport- Residential	General Service- Small	Customer Choice GS-Small	Agg Transport- GS-Small	Transport-TR-1
1	Units								
2	Throughput total	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168
3	Customers average	182,332	146,650	21,110	7	11,364	2,737	252	109
4	Commodity total	18,134,581	11,951,774	0	0	5,327,930	0	0	0
5									
6	Rate Base								
7	Cost of Gas								
8	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11	Sub-total	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12	Production								
13	Demand	\$2,088,448	\$905,118	\$127,913	\$183	\$370,254	\$86,740	\$33,576	\$114,474
14	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Commodity	\$1,714,597	\$1,130,022	\$0	\$0	\$503,748	\$0	\$0	\$0
16	Sub-total	\$3,803,045	\$2,035,139	\$127,913	\$183	\$874,002	\$86,740	\$33,576	\$114,474
17	Storage								
18	Demand	\$29,055,080	\$16,749,461	\$2,364,775	\$0	\$7,153,925	\$1,677,661	\$0	\$0
19	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	Sub-total	\$29,055,080	\$16,749,461	\$2,364,775	\$0	\$7,153,925	\$1,677,661	\$0	\$0
22	Transmission								
23	Demand	\$37,328,329	\$16,177,815	\$2,286,284	\$3,271	\$6,617,820	\$1,550,374	\$600,134	\$2,046,083
24	Customer	\$28,396,854	\$10,089,939	\$1,423,119	\$2,376	\$4,497,951	\$1,055,821	\$459,228	\$1,844,765
25	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
26	Sub-total	\$65,725,183	\$26,267,754	\$3,709,403	\$5,647	\$11,115,770	\$2,606,194	\$1,059,362	\$3,890,848
27	Distribution								
28	Demand	\$83,376,738	\$36,134,846	\$5,106,655	\$7,306	\$14,781,594	\$3,462,923	\$1,340,463	\$4,570,141
29	Customer	\$218,922,258	\$160,451,643	\$22,853,472	\$35,005	\$24,523,516	\$6,525,620	\$1,438,773	\$1,199,502
30	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	Sub-total	\$302,298,997	\$196,586,489	\$27,960,127	\$42,311	\$39,305,110	\$9,988,543	\$2,779,236	\$5,769,643
32	Customer								
33	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
34	Customer	\$5,945	\$4,240	\$604	\$3	\$615	\$149	\$122	\$93
35	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Sub-total	\$5,945	\$4,240	\$604	\$3	\$615	\$149	\$122	\$93
37	Grand Total								
38	Demand	\$151,848,596	\$69,967,240	\$9,885,627	\$10,761	\$28,923,593	\$6,777,698	\$1,974,174	\$6,730,699
39	Customer	\$247,325,057	\$170,545,822	\$24,277,195	\$37,384	\$29,022,082	\$7,581,590	\$1,898,123	\$3,044,359
40	Commodity	\$1,714,597	\$1,130,022	\$0	\$0	\$503,748	\$0	\$0	\$0
41	Sub-total	\$400,888,250	\$241,643,084	\$34,162,822	\$48,145	\$58,449,423	\$14,359,288	\$3,872,296	\$9,775,058

Source: Workpaper ALN-2

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	Large				Super Large	Other
			General Service-Large	Transport-TR-2	Customer Choice GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	Units							
2	Throughput total	33,636,752	854,602	6,659,678	21,109	26,200	3,126,872	275
3	Customers average	182,332	54	40	3	2	3	1
4	Commodity total	18,134,581	854,602	0	0	0	0	275
5								
6	Rate Base							
7	Cost of Gas							
8	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11	Sub-total	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12	Production							
13	Demand	\$2,088,448	\$41,528	\$270,193	\$1,590	\$1,747	\$124,489	\$10,642
14	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Commodity	\$1,714,597	\$80,801	\$0	\$0	\$0	\$0	\$26
16	Sub-total	\$3,803,045	\$122,330	\$270,193	\$1,590	\$1,747	\$124,489	\$10,668
17	Storage							
18	Demand	\$29,055,080	\$979,418	\$0	\$29,505	\$0	\$0	\$100,335
19	Customer	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	Sub-total	\$29,055,080	\$979,418	\$0	\$29,505	\$0	\$0	\$100,335
22	Transmission							
23	Demand	\$37,328,329	\$742,265	\$4,829,347	\$28,425	\$31,222	\$2,225,075	\$190,215
24	Customer	\$28,396,854	\$721,473	\$5,622,240	\$17,821	\$22,119	\$2,639,771	\$232
25	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
26	Sub-total	\$65,725,183	\$1,463,738	\$10,451,587	\$46,246	\$53,340	\$4,864,846	\$190,447
27	Distribution							
28	Demand	\$83,376,738	\$1,657,927	\$10,786,852	\$63,490	\$69,737	\$4,969,938	\$424,865
29	Customer	\$218,922,258	\$294,542	\$1,359,787	\$24,553	\$13,826	\$122,334	\$79,686
30	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	Sub-total	\$302,298,997	\$1,952,469	\$12,146,640	\$88,043	\$83,562	\$5,092,272	\$504,550
32	Customer							
33	Demand	\$0	\$0	\$0	\$0	\$0	\$0	\$0
34	Customer	\$5,945	\$19	\$84	\$1	\$1	\$12	\$2
35	Commodity	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Sub-total	\$5,945	\$19	\$84	\$1	\$1	\$12	\$2
37	Grand Total							
38	Demand	\$151,848,596	\$3,421,139	\$15,886,392	\$123,010	\$102,705	\$7,319,502	\$726,057
39	Customer	\$247,325,057	\$1,016,034	\$6,982,111	\$42,375	\$35,946	\$2,762,117	\$79,920
40	Commodity	\$1,714,597	\$80,801	\$0	\$0	\$0	\$0	\$26
41	Sub-total	\$400,888,250	\$4,517,974	\$22,868,503	\$165,385	\$138,650	\$10,081,619	\$806,003

Source: Workpaper ALN-2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Description	Total MGU Natural Gas	Residential			Small			Medium
			General Service- Residential	Customer Choice Residential	Agg Transport- Residential	General Service- Small	Customer Choice GS-Small	Agg Transport- GS-Small	Transport-TR-1
1	Units								
2	Throughput total	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168
3	Customers average	182,332	146,650	21,110	7	11,364	2,737	252	109
4	Commodity total	18,134,581	11,951,774	0	0	5,327,930	0	0	0
5									
6	Cost per Unit								
7	Cost of Gas								
8	Demand	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
9	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
10	Commodity	\$3.6016	\$3.5855	\$0.0000	\$0.0000	\$3.6141	\$0.0000	\$0.0000	\$0.0000
11	Production								
12	Demand	\$0.0394	\$0.0481	\$0.0482	\$0.0413	\$0.0442	\$0.0441	\$0.0392	\$0.0333
13	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
14	Commodity	\$0.0631	\$0.0631	\$0.0000	\$0.0000	\$0.0631	\$0.0000	\$0.0000	\$0.0000
15	Storage								
16	Demand	\$0.1980	\$0.2014	\$0.2016	\$0.0000	\$0.1930	\$0.1928	\$0.0000	\$0.0000
17	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
18	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
19	Transmission								
20	Demand	\$0.1653	\$0.2016	\$0.2020	\$0.1731	\$0.1850	\$0.1846	\$0.1643	\$0.1395
21	Customer	\$1.7408	\$0.7691	\$0.7535	\$3.7945	\$4.4243	\$4.3119	\$20.3694	\$189.1757
22	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
23	Distribution								
24	Demand	\$0.4839	\$0.5882	\$0.5894	\$0.5061	\$0.5415	\$0.5405	\$0.4819	\$0.4099
25	Customer	\$22.1201	\$20.3311	\$20.1558	\$93.7897	\$37.8986	\$41.4740	\$105.0503	\$187.6518
26	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
27	Customer								
28	Demand	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
29	Customer	\$4.6401	\$3.9888	\$3.9589	\$114.5473	\$6.9957	\$6.8146	\$124.5324	\$191.5034
30	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
31	Grand Total								
32	Demand	\$0.8866	\$1.0393	\$1.0413	\$0.7205	\$0.9636	\$0.9620	\$0.6854	\$0.5827
33	Customer	\$28.5011	\$25.0890	\$24.8683	\$212.1315	\$49.3186	\$52.6005	\$249.9521	\$568.3309
34	Commodity	\$3.6647	\$3.6487	\$0.0000	\$0.0000	\$3.6773	\$0.0000	\$0.0000	\$0.0000

Source: Exhibit A-16 Schedule F1.3

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	Large				Super Large	Other
			General Service-Large	Transport-TR-2	Customer Choice GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	Units							
2	Throughput total	33,636,752	854,602	6,659,678	21,109	26,200	3,126,872	275
3	Customers average	182,332	54	40	3	2	3	1
4	Commodity total	18,134,581	854,602	0	0	0	0	275
5								
6	Cost per Unit							
7	Cost of Gas							
8	Demand	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
9	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
10	Commodity	\$3.6016	\$3.7483	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$3.8548
11	Production							
12	Demand	\$0.0394	\$0.0309	\$0.0258	\$0.0479	\$0.0424	\$0.0253	\$24.6065
13	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
14	Commodity	\$0.0631	\$0.0631	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0631
15	Storage							
16	Demand	\$0.1980	\$0.1647	\$0.0000	\$0.2009	\$0.0000	\$0.0000	\$52.4752
17	Customer	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
18	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
19	Transmission							
20	Demand	\$0.1653	\$0.1294	\$0.1080	\$0.2006	\$0.1775	\$0.1060	\$103.0938
21	Customer	\$1.7408	\$149.4257	\$1,571.0873	\$66.3983	\$113.7896	\$9,835.4880	\$2.5931
22	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
23	Distribution							
24	Demand	\$0.4839	\$0.3795	\$0.3184	\$0.5895	\$0.5219	\$0.3128	\$304.4107
25	Customer	\$22.1201	\$97.3090	\$621.4384	\$127.9604	\$112.0813	\$634.0180	\$1,755.3464
26	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
27	Customer							
28	Demand	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
29	Customer	\$4.6401	\$77.2051	\$419.3249	\$43.7050	\$168.8383	\$1,512.8886	\$320.6690
30	Commodity	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000
31	Grand Total							
32	Demand	\$0.8866	\$0.7045	\$0.4522	\$1.0388	\$0.7418	\$0.4441	\$484.5861
33	Customer	\$28.5011	\$323.9399	\$2,611.8507	\$238.0636	\$394.7093	\$11,982.3945	\$2,078.6086
34	Commodity	\$3.6647	\$3.8115	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$3.9179

Source: Exhibit A-16 Schedule F1.3

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	Line Description	Total MGU Natural Gas	Total GS Residential	Total GS Small Commercial	Total GS Large Commercial	Total Transport	Total Special Contract
1	Development of Rate Base						
2	Net Plant						
3	Utility Plant in Service	614,691,824	385,406,309	81,408,990	6,008,676	140,755,655	1,112,195
4	Construction Work in Progress	6,778,850	4,323,436	881,438	70,923	1,489,246	13,808
5	Accumulated Depreciation	(254,172,180)	(162,970,304)	(31,263,346)	(2,365,276)	(57,109,920)	(463,333)
6	Net Plant	367,298,494	226,759,440	51,027,082	3,714,322	85,134,981	662,669
7	Other Rate Base Components						
8	Gas Stored Underground	7,424,791	4,280,190	1,828,128	250,282	1,040,551	25,640
9	Material and Supplies	1,092,712	735,553	129,103	6,317	220,040	1,700
10	Prepayments	52,725	31,931	7,566	592	12,530	106
11	Cash & Bank Balances	1,968,086	852,953	348,916	39,135	717,053	10,029
12	Working Capital	23,051,441	10,124,130	4,182,523	493,171	8,145,705	105,912
13	Other Rate Base Components	33,589,756	16,024,757	6,496,235	789,498	10,135,880	143,386
14	Total Rate Base						
15	Total Rate Base	400,888,250	242,784,197	57,523,317	4,503,820	95,270,861	806,055
16	Operating Income						
17	Operating Revenues						
18	Sales Revenue	141,029,474	85,644,158	32,905,083	4,428,247	17,954,822	97,164
19	Other Operating Revenues	1,130,765	691,874	176,709	14,640	246,324	1,218
20	Other Misc Revenues	0	0	0	0	0	0
21	Operating Revenues	142,160,240	86,336,033	33,081,792	4,442,887	18,201,146	98,382
22	Operating Expenses						
23	Operation & Maintenance	100,277,695	65,806,328	23,505,798	3,478,679	7,435,319	51,571
24	Book Depreciation Expense	19,225,123	12,655,160	2,395,537	151,203	3,992,628	30,596
25	Taxes Other than Income Taxes	7,474,961	4,386,885	1,092,659	90,517	1,887,072	17,827
26	State Income Taxes	(775,137)	(469,435)	(111,224)	(8,708)	(184,211)	(1,559)
27	Federal Income Taxes	(1,950,743)	(1,181,400)	(279,911)	(21,916)	(463,593)	(3,922)
28	Deferred Income Taxes	3,721,155	2,253,590	533,947	41,806	884,330	7,482
29	Regulatory Debits and Credits	2,500,000	1,514,039	358,724	28,087	594,124	5,027
30	Investment Tax Credits	(18,172)	(11,005)	(2,608)	(204)	(4,319)	(37)
31	Operating Expenses	130,454,882	84,954,160	27,492,922	3,759,462	14,141,351	106,985
32	Revenue Deficiency						
33	Revenue Deficiency at Present Rates						
34	Adjustments to Operating Income	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	1,381,872	5,588,870	683,425	4,059,795	(8,604)
36	Earned Rate Of Return	0.0292	0.0057	0.0972	0.1517	0.0426	(0.0107)
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	0.0515	(0.0399)	(0.0945)	0.0146	0.0679
39	Income Deficiency (Sufficiency) \$	11,233,708	12,510,385	(2,297,351)	(425,713)	1,391,661	54,727
40	Tax Gross-up Factor	0.3466					
41	Additional Taxes on Income Deficiency	3,893,828	2,358,163	558,724	43,746	925,366	7,829
42	Revenue Deficiency (Sufficiency) \$	15,127,536	14,868,548	(1,738,627)	(381,968)	2,317,026	62,556
43	Revenue Deficiency (Sufficiency) %	0.1073	0.1736	(0.0528)	(0.0863)	0.1290	0.6438
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	14,868,548	(1,738,627)	(381,968)	2,317,026	62,556
46	Revenue Deficiency After Specified Adjustments %	0.1073	0.1736	(0.0528)	(0.0863)	0.1290	0.6438
47	Adjustments to Requested Revenue	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	14,868,548	(1,738,627)	(381,968)	2,317,026	62,556
49	Revenue Deficiency For 2021 Rate Design %	0.1073	0.1736	(0.0528)	(0.0863)	0.1290	0.6438
50	Sales Revenue	141,029,474	85,644,158	32,905,083	4,428,247	17,954,822	97,164
51	Revenue Requirement	156,157,011	100,512,707	31,166,456	4,046,279	20,271,849	159,720
52	Cost of Gas	65,313,503	42,853,300	19,255,797	3,203,346	0	1,059
53	Revenue Requirement excl Gas Costs	90,843,508	57,659,406	11,910,658	842,933	20,271,849	158,661

Source: Exhibit A-16 Schedule F1.7

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Description	Total MGU Natural Gas	Residential			Small			Medium
			General Service-Residential	Customer Choice-Residential	Agg Transport-Residential	General Service-Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1
1	Development of Rate Base								
2	Net Plant								
3	Utility Plant in Service	614,691,824	385,406,309	54,664,163	65,484	81,408,990	19,850,792	5,332,970	13,667,583
4	Construction Work in Progress	6,778,850	4,323,436	606,477	559	881,438	205,280	52,256	142,494
5	Accumulated Depreciation	(254,172,180)	(162,970,304)	(23,185,549)	(20,929)	(31,263,346)	(7,506,869)	(1,940,921)	(5,377,506)
6	Net Plant	367,298,494	226,759,440	32,085,091	45,115	51,027,082	12,549,203	3,444,304	8,432,571
7	Other Rate Base Components								
8	Gas Stored Underground	7,424,791	4,280,190	604,299	0	1,828,128	428,713	0	0
9	Material and Supplies	1,092,712	735,553	104,926	128	129,103	32,353	8,558	18,175
10	Prepayments	52,725	31,931	4,517	6	7,566	1,850	503	1,281
11	Cash & Bank Balances	1,968,086	852,953	120,541	172	348,916	81,741	31,641	107,877
12	Working Capital	23,051,441	10,124,130	1,421,288	1,859	4,182,523	973,281	342,312	1,183,116
13	Other Rate Base Components	33,589,756	16,024,757	2,255,570	2,165	6,496,235	1,517,939	383,014	1,310,449
14	Total Rate Base								
15	Total Rate Base	400,888,250	242,784,197	34,340,661	47,280	57,523,317	14,067,141	3,827,318	9,743,020
16	Operating Income								
17	Operating Revenues								
18	Sales Revenue	141,029,474	85,644,158	5,968,608	7,365	32,905,083	3,134,341	1,034,136	2,678,943
19	Other Operating Revenues	1,130,765	691,874	97,336	99	176,709	40,863	12,602	31,992
20	Other Misc Revenues	0	0	0	0	0	0	0	0
21	Operating Revenues	142,160,240	86,336,033	6,065,943	7,464	33,081,792	3,175,204	1,046,738	2,710,934
22	Operating Expenses								
23	Operation & Maintenance	100,277,695	65,806,328	3,220,892	15,530	23,505,798	999,038	689,663	730,552
24	Book Depreciation Expense	19,225,123	12,655,160	1,788,111	2,006	2,395,537	580,058	145,390	339,114
25	Taxes Other than Income Taxes	7,474,961	4,386,885	623,277	840	1,092,659	267,276	76,434	207,613
26	State Income Taxes	(775,137)	(469,435)	(66,399)	(91)	(111,224)	(27,200)	(7,400)	(18,839)
27	Federal Income Taxes	(1,950,743)	(1,181,400)	(167,103)	(230)	(279,911)	(68,451)	(18,624)	(47,410)
28	Deferred Income Taxes	3,721,155	2,253,590	318,759	439	533,947	130,575	35,526	90,437
29	Regulatory Debits and Credits	2,500,000	1,514,039	214,154	295	358,724	87,725	23,868	60,759
30	Investment Tax Credits	(18,172)	(11,005)	(1,557)	(2)	(2,608)	(638)	(173)	(442)
31	Operating Expenses	130,454,882	84,954,160	5,930,134	18,786	27,492,922	1,968,383	944,683	1,361,785
32	Revenue Deficiency								
33	Revenue Deficiency at Present Rates								
34	Adjustments to Operating Income	0	0	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	1,381,872	135,809	(11,322)	5,588,870	1,206,821	102,055	1,349,149
36	Earned Rate Of Return	0.0292	0.0057	0.0040	(0.2395)	0.0972	0.0858	0.0267	0.1385
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	0.0515	0.0533	0.2967	(0.0399)	(0.0286)	0.0306	(0.0813)
39	Income Deficiency (Sufficiency) \$	11,233,708	12,510,385	1,829,184	14,027	(2,297,351)	(401,891)	116,947	(791,648)
40	Tax Gross-up Factor	0.3466							
41	Additional Taxes on Income Deficiency	3,893,828	2,358,163	333,551	459	558,724	136,634	37,175	94,634
42	Revenue Deficiency (Sufficiency) \$	15,127,536	14,868,548	2,162,735	14,487	(1,738,627)	(265,257)	154,121	(697,014)
43	Revenue Deficiency (Sufficiency) %	0.1073	0.1736	0.3624	1.9668	(0.0528)	(0.0846)	0.1490	(0.2602)
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	14,868,548	2,162,735	14,487	(1,738,627)	(265,257)	154,121	(697,014)
46	Revenue Deficiency After Specified Adjustments %	0.1073	0.1736	0.3624	1.9668	(0.0528)	(0.0846)	0.1490	(0.2602)
47	Adjustments to Requested Revenue	0	0	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	14,868,548	2,162,735	14,487	(1,738,627)	(265,257)	154,121	(697,014)
49	Revenue Deficiency For 2021 Rate Design %	0.1073	0.1736	0.3624	1.9668	(0.0528)	(0.0846)	0.1490	(0.2602)
50	Sales Revenue	141,029,474	85,644,158	5,968,608	7,365	32,905,083	3,134,341	1,034,136	2,678,943
51	Revenue Requirement	156,157,011	100,512,707	8,131,342	21,852	31,166,456	2,869,084	1,188,257	1,981,928
52	Cost of Gas	65,313,503	42,853,300	0	0	19,255,797	0	0	0
53	Revenue Requirement excl Gas Costs	90,843,508	57,659,406	8,131,342	21,852	11,910,658	2,869,084	1,188,257	1,981,928

Source: Col. (B): Exhibit A-11 through A-14, Cols. (C) to (O): Workpaper ALN-3

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	Large			Super Large		Other
			General Service-Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	
1	Development of Rate Base							
2	Net Plant							
3	Utility Plant in Service	614,691,824	6,008,676	32,523,703	216,772	192,674	14,241,514	1,112,195
4	Construction Work in Progress	6,778,850	70,923	330,372	2,443	2,108	147,257	13,808
5	Accumulated Depreciation	(254,172,180)	(2,365,276)	(13,155,189)	(81,749)	(76,309)	(5,764,899)	(463,333)
6	Net Plant	367,298,494	3,714,322	19,698,886	137,466	118,473	8,623,872	662,669
7	Other Rate Base Components							
8	Gas Stored Underground	7,424,791	250,282	0	7,540	0	0	25,640
9	Material and Supplies	1,092,712	6,317	39,150	274	263	16,214	1,700
10	Prepayments	52,725	592	3,007	22	18	1,326	106
11	Cash & Bank Balances	1,968,086	39,135	254,621	1,499	1,646	117,314	10,029
12	Working Capital	23,051,441	493,171	2,865,410	17,684	17,707	1,323,050	105,912
13	Other Rate Base Components	33,589,756	789,498	3,162,188	27,018	19,633	1,457,904	143,386
14	Total Rate Base							
15	Total Rate Base	400,888,250	4,503,820	22,861,074	164,484	138,106	10,081,776	806,055
16	Operating Income							
17	Operating Revenues							
18	Sales Revenue	141,029,474	4,428,247	3,757,984	37,089	38,688	1,297,670	97,164
19	Other Operating Revenues	1,130,765	14,640	46,221	449	462	16,299	1,218
20	Other Misc Revenues	0	0	0	0	0	0	0
21	Operating Revenues	142,160,240	4,442,887	3,804,205	37,538	39,150	1,313,969	98,382
22	Operating Expenses							
23	Operation & Maintenance	100,277,695	3,478,679	1,259,443	9,351	11,779	499,071	51,571
24	Book Depreciation Expense	19,225,123	151,203	795,267	5,321	4,723	332,638	30,596
25	Taxes Other than Income Taxes	7,474,961	90,517	487,707	3,380	3,001	217,545	17,827
26	State Income Taxes	(775,137)	(8,708)	(44,203)	(318)	(267)	(19,494)	(1,559)
27	Federal Income Taxes	(1,950,743)	(21,916)	(111,243)	(800)	(672)	(49,058)	(3,922)
28	Deferred Income Taxes	3,721,155	41,806	212,203	1,527	1,282	93,582	7,482
29	Regulatory Debits and Credits	2,500,000	28,087	142,565	1,026	861	62,871	5,027
30	Investment Tax Credits	(18,172)	(204)	(1,036)	(7)	(6)	(457)	(37)
31	Operating Expenses	130,454,882	3,759,462	2,740,702	19,479	20,701	1,136,698	106,985
32	Revenue Deficiency							
33	Revenue Deficiency at Present Rates							
34	Adjustments to Operating Income	0	0	0	0	0	0	0
35	Adjusted Operating Income	11,705,358	683,425	1,063,504	18,059	18,449	177,271	(8,604)
36	Earned Rate Of Return	0.0292	0.1517	0.0465	0.1098	0.1336	0.0176	(0.0107)
37	Required Rate Of Return	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572	0.0572
38	Income Deficiency (Sufficiency) %	0.0280	(0.0945)	0.0107	(0.0526)	(0.0764)	0.0396	0.0679
39	Income Deficiency (Sufficiency) \$	11,233,708	(425,713)	244,621	(8,647)	(10,546)	399,615	54,727
40	Tax Gross-up Factor	0.3466						
41	Additional Taxes on Income Deficiency	3,893,828	43,746	222,050	1,598	1,341	97,924	7,829
42	Revenue Deficiency (Sufficiency) \$	15,127,536	(381,968)	466,670	(7,050)	(9,205)	497,539	62,556
43	Revenue Deficiency (Sufficiency) %	0.1073	(0.0863)	0.1242	(0.1901)	(0.2379)	0.3834	0.6438
44	Adjustments to Revenue Deficiency	0	0	0	0	0	0	0
45	Revenue Deficiency After Specified Adjustments \$	15,127,536	(381,968)	466,670	(7,050)	(9,205)	497,539	62,556
46	Revenue Deficiency After Specified Adjustments %	0.1073	(0.0863)	0.1242	(0.1901)	(0.2379)	0.3834	0.6438
47	Adjustments to Requested Revenue	0	0	0	0	0	0	0
48	Revenue Deficiency For 2021 Rate Design \$	15,127,536	(381,968)	466,670	(7,050)	(9,205)	497,539	62,556
49	Revenue Deficiency For 2021 Rate Design %	0.1073	(0.0863)	0.1242	(0.1901)	(0.2379)	0.3834	0.6438
50	Sales Revenue	141,029,474	4,428,247	3,757,984	37,089	38,688	1,297,670	97,164
51	Revenue Requirement	156,157,011	4,046,279	4,224,654	30,039	29,483	1,795,208	159,720
52	Cost of Gas	65,313,503	3,203,346	0	0	0	0	1,059
53	Revenue Requirement excl Gas Costs	90,843,508	842,933	4,224,654	30,039	29,483	1,795,208	158,661

Source: Col. (B): Exhibit A-11 through A-14, Cols. (C) to (O): Workpaper ALN-3

Schedule F2.1

**Michigan Public Service Commission
Michigan Gas Utilities Corporation
Summary of Present and Proposed Revenue by Rate Schedule
Including Cost of Gas**

Case No.: U-20718
Exhibit No.: A-16
Schedule: F2.1
Page: 1 of 1
Witness: Shannon Burzycki

Line No.	(a) MGUC Rate Schedule	(b) Total Current Revenue (\$000)	(c) Total Proposed Revenue (\$000)	(d) Total Net Revenue Increase (\$000)	(e) Revenue Increase %
1	Residential	\$85,834	\$92,896	\$7,063	8.2%
2	General Service - Small (incl. Comm. Lighting)	26,546	30,219	3,673	13.8%
3	General Service - Medium	6,291	6,764	473	7.5%
4	General Service - Large	4,303	4,568	265	6.1%
5	Special Contract	97	97	0	0.1%
6	TR-1 Transport	2,679	3,239	560	20.9%
7	TR-2 Transport	3,758	4,278	520	13.8%
8	TR-3 Transport	1,298	1,471	173	13.4%
9	Aggregated - Residential to Residential	7	8	1	15.3%
10	Aggregated - Small to General Service - Small	1,034	1,343	309	29.9%
11	Aggregated - Small to General Service - Medium	0	0	0	0.0%
12	Aggregated - Large to General Service - Large	39	47	9	22.0%
13	Choice - Residential	5,969	7,001	1,032	17.3%
14	Choice - General Service - Small	2,747	3,658	911	33.2%
15	Choice - General Service - Medium	387	520	133	34.4%
16	Choice - General Service - Large	37	44	7	18.5%
17					
18	TOTAL MGUC	\$141,026	\$156,154	\$15,128	10.7%

Note: Gas costs are included in both the Current Revenues or the Proposed Revenues above.

Schedule F2.2

**Michigan Public Service Commission
Michigan Gas Utilities Corporation
Summary of Present and Proposed Revenue by Rate Schedule
Excluding Cost of Gas**

Case No.: U-20718
Exhibit No.: A-16
Schedule: F2.2
Page: 1 of 1
Witness: Shannon Burzycki

Line No.	(a) MGUC Rate Schedule	(b)	(c)	(d)	(e)
		Total Current Revenue (\$000)	Total Proposed Revenue (\$000)	Total Net Revenue Increase (\$000)	Revenue Increase %
1	Residential	\$42,788	\$49,851	\$7,063	16.5%
2	General Service - Small (incl. Comm. Lighting)	11,594	15,267	3,673	31.7%
3	General Service - Medium	2,055	2,527	473	23.0%
4	General Service - Large	1,225	1,490	265	21.6%
5	Special Contract	96	96	0	0.1%
6	TR-1 Transport	2,679	3,239	560	20.9%
7	TR-2 Transport	3,758	4,278	520	13.8%
8	TR-3 Transport	1,298	1,471	173	13.4%
9	Aggregated - Residential to Residential	7	8	1	15.3%
10	Aggregated - Small to General Service - Small	1,034	1,343	309	29.9%
11	Aggregated - Small to General Service - Medium	0	0	0	0.0%
12	Aggregated - Large to General Service - Large	39	47	9	22.0%
13	Choice - Residential	5,969	7,001	1,032	17.3%
14	Choice - General Service - Small	2,747	3,658	911	33.2%
15	Choice - General Service - Medium	387	520	133	34.4%
16	Choice - General Service - Large	37	44	7	18.5%
17					
18	TOTAL MGUC	\$75,712	\$90,840	\$15,128	20.0%

Note: No gas costs are included in either the Current Revenues or the Proposed Revenues above.

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.1
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(c)	(d)	(e)	(f)	(g)
		Quantity	Units		Rate	Revenue	Rate	Revenue
1	Residential							
2	Monthly Customer Charge	1,759,629	Bills		\$13.00	\$22,875,177	\$14.75	\$25,954,528
3	Distribution Charge	11,951,773.9	Mcf		1.5871	18,968,660	1.9363	23,142,220
4	Gas Supply Acquisition Charge	11,951,773.9	Mcf		0.0790	944,190	0.0631	754,157
5	Cost of Gas	11,951,773.9	Mcf		3.6016	43,045,506	3.6016	43,045,506
6	Total Residential					\$85,833,533		\$92,896,410
7								
8	Notice Calculation							
9	Monthly Customer Charges	12	Bills		\$13.00	\$156	\$14.75	\$177
10	Distribution Charge	82.0	Mcf		1.5871	130	1.9363	159
11	Gas Supply Acquisition Charge	82.0	Mcf		0.0790	6	0.0631	5
12	Cost of Gas	82.0	Mcf		3.6016	295	3.6016	295
13	Total Annual Residential Bill					\$588		\$636
14								
15	Annual Residential Increase						8.2%	\$48.33
16	Monthly Residential Increase						8.2%	\$4.03

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.1
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(d) Rate	(e) Revenue	(f) Rate	(g) Revenue
		Quantity	Units				
1	General Service - Small (incl. Comm. Lighting)						
2	Monthly Customer Charge	133,635	Bills	\$35.00	\$4,677,225	\$47.50	\$6,347,663
3	Distribution Charge	4,151,611.7	Mcf	1.5870	6,588,608	2.0853	8,657,356
4	Gas Supply Acquisition Charge	4,151,611.7	Mcf	0.0790	327,977	0.0631	261,967
5	Cost of Gas	4,151,611.7	Mcf	3.6016	14,952,444	3.6016	14,952,444
6	Total General Service - Small				\$26,546,254		\$30,219,429
7							
8							
9	General Service - Medium						
10	Monthly Customer Charge	2,712	Bills	35.00	\$94,920	135.00	\$366,120
11	Distribution Charge	1,176,318.7	Mcf	1.5870	1,866,818	1.7741	2,086,907
12	Gas Supply Acquisition Charge	1,176,318.7	Mcf	0.0790	92,929	0.0631	74,226
13	Cost of Gas	1,176,318.7	Mcf	3.6016	4,236,629	3.6016	4,236,629
14	Total General Service - Large				\$6,291,296		\$6,763,882
15							
16							
17	General Service - Large						
18	Monthly Customer Charge	648	Bills	\$425.00	\$275,438	\$425.00	\$275,438
19	Distribution Charge	854,602.1	Mcf	1.0322	882,120	1.3577	1,160,293
20	Gas Supply Acquisition Charge	854,602.1	Mcf	0.0790	67,514	0.0631	53,925
21	Cost of Gas	854,602.1	Mcf	3.6016	3,077,935	3.6016	3,077,935
22	Total General Service - Large				\$4,303,007		\$4,567,592

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
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Witness: Shannon Burzycki

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		Billing Determinants		Present		Proposed	
No.	Description	Quantity	Units	Rate	Revenue	Rate	Revenue
1	Special Contract						
2	Monthly Customer Charge	12	Bills	\$7,983.25	\$95,799	\$7,983.25	\$95,799
3	Distribution Charge	274.8	Mcf	1.1112	305	1.4208	390
4	Gas Supply Acquisition Charge	274.8	Mcf	0.0000	0	0.0000	0
5	Cost of Gas	274.8	Mcf	3.6016	990	3.6016	990
6	Total Special Contract				\$97,094		\$97,179

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
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Witness: Shannon Burzycki

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line		Billing Determinants		Present		Proposed	
No.	Description	Quantity	Units	Rate	Revenue	Rate	Revenue
1	TR-1 Transport						
2	Customer Charge	1,308	Bills	\$850.00	\$1,111,800	\$1,200.00	\$1,569,600
3	Distribution Charge - Peak	1,303,347.6	Mcf	0.7777	1,013,613	0.8244	1,074,480
4	Off Peak	881,820.3	Mcf	0.6277	553,519	0.6744	594,700
5	Total TR-1 Transport				\$2,678,932		\$3,238,779
1	TR-2 Transport						
2	Customer Charge	480	Bills	\$ 2,250.00	\$1,080,000	\$ 2,600.00	\$1,248,000
3	Distribution Charge - Peak	3,219,594.5	Mcf	0.4796	1,544,118	0.5324	1,714,112
4	Off Peak	3,440,083.6	Mcf	0.3296	1,133,852	0.3824	1,315,488
5	Total TR-2 Transport				\$3,757,969		\$4,277,600
1	TR-3 Transport						
2	Customer Charge	36	Bills	\$ 3,050.00	\$109,800	\$ 3,300.00	\$118,800
3	Distribution Charge - Peak	1,350,581.0	Mcf	0.4651	628,155	0.5177	699,196
4	Off Peak	1,776,291.0	Mcf	0.3151	559,709	0.3677	653,142
5	Total TR-3 Transport				\$1,297,665		\$1,471,138

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.1
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Line No.	(a) Description	(b) Billing Determinants		(d) Rate	(e) Present Revenue	(f) Rate	(g) Proposed Revenue
		Quantity	Units				
1	Aggregated - Residential to Residential						
2	Customer Charge	84	Bills	\$ 34.50	\$2,898	\$ 36.25	\$3,045
3	Distribution Charge	2,814.8	Mcf	1.5871	4,467	1.9363	5,450
4	Total				<u>\$7,365</u>		<u>\$8,495</u>
5							
6	Aggregated - Small to General Service - Small						
7	Customer Charge	3,024	Bills	56.50	\$170,856	69.00	\$ 208,656
8	Distribution Charge	543,966.2	Mcf	1.5870	863,274	2.0853	1,134,333
9	Total				<u>\$1,034,130</u>		<u>\$1,342,989</u>
10							
11	Aggregated - Small to General Service - Medium						
12	Customer Charge	0	Bills	56.50	\$0	156.50	\$ -
13	Distribution Charge	0.0	Mcf	1.5870	0	1.7741	0
14	Total				<u>\$0</u>		<u>\$0</u>
15							
16	Aggregated - Large to General Service - Large						
17	Customer Charge	26	Bills	446.50	\$11,698	446.50	\$ 11,698
18	Distribution Charge	26,200.0	Mcf	1.0322	27,044	1.3577	35,572
19	Total				<u>\$38,742</u>		<u>\$47,270</u>
20							
21	Total Aggregated				<u>\$1,080,238</u>		<u>\$1,398,754</u>

Schedule F3.1

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Including Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(c) Units	(d) Rate	(e) Present		(f) Rate	(g) Proposed	
		Quantity				Revenue			Revenue	
1	Choice - Residential									
2	Customer Charge	253,320	Bills		\$ 13.00	\$3,293,160		\$ 14.75	\$3,736,470	
3	Distribution Charge	1,685,717.9	Mcf		1.5871	2,675,403		1.9363	3,264,056	
4	Total					\$5,968,563			\$7,000,526	
5										
6	Choice - General Service - Small									
7	Customer Charge	31,932	Bills		35.00	\$1,117,620		47.50	\$1,516,770	
8	Distribution Charge	1,026,997.4	Mcf		1.5870	1,629,845		2.0853	2,141,598	
9	Total					\$2,747,465			\$3,658,368	
10										
11	Choice - General Service - Medium									
12	Customer Charge	912	Bills		35.00	\$31,920		135.00	\$123,120	
13	Distribution Charge	223,647.4	Mcf		1.5870	354,928		1.7741	396,773	
14	Total					\$386,848			\$519,893	
15										
16	Choice - General Service - Large									
17	Customer Charge	36	Bills		425.00	\$15,300		425.00	\$15,300	
18	Distribution Charge	21,109.2	Mcf		1.0322	21,789		1.3577	28,660	
19	Total					\$37,089			\$43,960	
20										
21	Total Choice					\$8,753,117			\$10,702,853	
22										
23	MGUC Totals									
24	Monthly Customer Charge	2,184,170	Bills			\$34,836,772			\$41,101,767	
25	Distribution Charge	32,236,785.9	Mcf			37,094,481			45,621,045	
26	Gas Supply Acquisition Charge	16,958,262.5	Mcf			1,339,681			1,144,275	
27	Cost of Gas	16,958,262.5	Mcf			61,076,874			65,313,503	
28	Total MGUC					\$134,347,808			\$153,180,589	

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(d) Rate	(e) Present Revenue	(f) Rate	(g) Proposed Revenue
		Quantity	Units				
1	Residential						
2	Monthly Customer Charge	1,759,629	Bills	\$13.00	\$22,875,177	\$14.75	\$25,954,528
3	Distribution Charge	11,951,773.9	Mcf	1.5871	18,968,660	1.9363	23,142,220
4	Gas Supply Acquisition Charge	11,951,773.9	Mcf	0.0790	944,190	0.0631	754,157
5	Cost of Gas	11,951,773.9	Mcf	0.0000	0	0.0000	0
6	Total Residential				\$42,788,028		\$49,850,905
7							
8	Notice Calculation						
9	Monthly Customer Charges	12	Bills	\$13.00	\$156	\$14.75	\$177
10	Distribution Charge	82.0	Mcf	1.5871	130	1.9363	159
11	Gas Supply Acquisition Charge	82.0	Mcf	0.0790	6	0.0631	5
12	Cost of Gas	82.0	Mcf	0.0000	0	0.0000	0
13	Total Annual Residential Bill				\$293		\$341
14							
15	Annual Residential Increase						\$48.33
16							
17	Monthly Residential Increase						\$4.03

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.2
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(d) Rate	(e) Present Revenue	(f) Proposed Rate	(g) Proposed Revenue
		Quantity	Units				
1	General Service - Small (incl. Comm. Lighting)						
2	Monthly Customer Charge	133,635	Bills	\$35.00	\$4,677,225	\$47.50	\$6,347,663
3	Distribution Charge	4,151,611.7	Mcf	1.5870	6,588,608	2.0853	8,657,356
4	Gas Supply Acquisition Charge	4,151,611.7	Mcf	0.0790	327,977	0.0631	261,967
5	Cost of Gas	4,151,611.7	Mcf	0.0000	0	0.0000	0
6	Total General Service - Small				\$11,593,810		\$15,266,985
7							
8							
9	General Service - Medium						
10	Monthly Customer Charge	2,712	Bills	35.00	\$94,920	135.00	\$366,120
11	Distribution Charge	1,176,318.7	Mcf	1.5870	1,866,818	1.7741	2,086,907
12	Gas Supply Acquisition Charge	1,176,318.7	Mcf	0.0790	92,929	0.0631	74,226
13	Cost of Gas	1,176,318.7	Mcf	0.0000	0	0.0000	0
14	Total General Service - Large				\$2,054,667		\$2,527,253
15							
16							
17	General Service - Large						
18	Monthly Customer Charge	648	Bills	\$425.00	\$275,438	\$425.00	\$275,438
19	Distribution Charge	854,602.1	Mcf	1.0322	882,120	1.3577	1,160,293
20	Gas Supply Acquisition Charge	854,602.1	Mcf	0.0790	67,514	0.0631	53,925
21	Cost of Gas	854,602.1	Mcf	0.0000	0	0.0000	0
22	Total General Service - Large				\$1,225,072		\$1,489,657

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.2
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(c) Present		(d) Proposed	
		Quantity	Units	Rate	Revenue	Rate	Revenue
1	Special Contract						
2	Monthly Customer Charge	12	Bills	\$7,983.25	\$95,799	\$7,983.25	\$95,799
3	Distribution Charge	274.8	Mcf	1.1112	305	1.4208	390
4	Gas Supply Acquisition Charge	274.8	Mcf	0.0000	0	0.0000	0
5	Cost of Gas	274.8	Mcf	0.0000	0	0.0000	0
6	Total Special Contract				\$96,104		\$96,189

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-20718
Exhibit No.: A-16
Schedule: F3.2
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(c) Present		(d) Proposed	
		Quantity	Units	Rate	Revenue	Rate	Revenue
1	TR-1 Transport						
2	Customer Charge	1,308	Bills	\$850.00	\$1,111,800	\$1,200.00	\$1,569,600
3	Distribution Charge - Peak	1,303,347.6	Mcf	0.7777	1,013,613	0.8244	1,074,480
4	Off Peak	881,820.3	Mcf	0.6277	553,519	0.6744	594,700
5	Total TR-1 Transport				\$2,678,932		\$3,238,779
6							
7							
8	TR-2 Transport						
9	Customer Charge	480	Bills	\$ 2,250.00	\$1,080,000	\$ 2,600.00	\$1,248,000
10	Distribution Charge - Peak	3,219,594.5	Mcf	0.4796	1,544,118	0.5324	1,714,112
11	Off Peak	3,440,083.6	Mcf	0.3296	1,133,852	0.3824	1,315,488
12	Total TR-2 Transport				\$3,757,969		\$4,277,600
13							
14							
15	TR-3 Transport						
16	Customer Charge	36	Bills	\$ 3,050.00	\$109,800	\$ 3,300.00	\$118,800
17	Distribution Charge - Peak	1,350,581.0	Mcf	0.4651	628,155	0.5177	699,196
18	Off Peak	1,776,291.0	Mcf	0.3151	559,709	0.3677	653,142
19	Total TR-3 Transport				\$1,297,665		\$1,471,138

Schedule F3.2

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas

Case No.: U-20718
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Line No.	(a) Description	(b) Billing Determinants		(c) Units	(d) Rate	(e) Present		(f) Rate	(g) Proposed	
		Quantity				Revenue			Revenue	
1	Aggregated - Residential to Residential									
2	Customer Charge	84	Bills		\$ 34.50	\$2,898		\$ 36.25	\$3,045	
3	Distribution Charge	2,814.8	Mcf		1.5871	4,467		1.9363	5,450	
4	Total					\$7,365			\$8,495	
5										
6	Aggregated - Small to General Service - Small									
7	Customer Charge	3,024	Bills		56.50	\$170,856		69.00	\$ 208,656	
8	Distribution Charge	543,966.2	Mcf		1.5870	863,274		2.0853	1,134,333	
9	Total					\$1,034,130			\$1,342,989	
10										
11	Aggregated - Small to General Service - Medium									
12	Customer Charge	0	Bills		56.50	\$0		156.50	\$ -	
13	Distribution Charge	0.0	Mcf		1.5870	0		1.7741	0	
14	Total					\$0			\$0	
15										
16	Aggregated - Large to General Service - Large									
17	Customer Charge	26	Bills		446.50	\$11,698		446.50	\$ 11,698	
18	Distribution Charge	26,200.0	Mcf		1.0322	27,044		1.3577	35,572	
19	Total					\$38,742			\$47,270	
20										
21	Total Aggregated					\$1,080,238			\$1,398,754	

Schedule F3.2

**Michigan Public Service Commission
Michigan Gas Utilities Corporation
Present and Proposed Revenue Detail Excluding Cost of Gas**

Case No.: U-20718
Exhibit No.: A-16
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Witness: Shannon Burzycki

Line No.	(a) Description	(b) Billing Determinants		(c) Units	(d) Rate	(e) Present		(f) Rate	(g) Proposed	
		Quantity					Revenue			Revenue
1	Choice - Residential									
2	Customer Charge	253,320	Bills	\$	13.00		\$3,293,160	\$	14.75	\$3,736,470
3	Distribution Charge	1,685,717.9	Mcf		1.5871		2,675,403		1.9363	3,264,056
4	Total						<u>\$5,968,563</u>			<u>\$7,000,526</u>
5										
6	Choice - General Service - Small									
7	Customer Charge	31,932	Bills		35.00		\$1,117,620		47.50	\$1,516,770
8	Distribution Charge	1,026,997.4	Mcf		1.5870		1,629,845		2.0853	2,141,598
9	Total						<u>\$2,747,465</u>			<u>\$3,658,368</u>
10										
11	Choice - General Service - Medium									
12	Customer Charge	912	Bills		35.00		\$31,920		135.00	\$123,120
13	Distribution Charge	223,647.4	Mcf		1.5870		354,928		1.7741	396,773
14	Total						<u>\$386,848</u>			<u>\$519,893</u>
15										
16	Choice - General Service - Large									
17	Customer Charge	36	Bills		425.00		\$15,300		425.00	\$15,300
18	Distribution Charge	21,109.2	Mcf		1.0322		21,789		1.3577	28,660
19	Total						<u>\$37,089</u>			<u>\$43,960</u>
20										
21	Total Choice						<u>\$8,753,117</u>			<u>\$10,702,853</u>
22										
23	MGUC Totals									
24	Monthly Customer Charge	2,184,170	Bills				\$34,963,612			\$41,101,767
25	Distribution Charge	32,236,785.9	Mcf				37,094,481			45,621,045
26	Gas Supply Acquisition Charge	16,958,262.5	Mcf				1,339,681			1,144,275
27	Cost of Gas	16,958,262.5	Mcf				0			0
28	Total MGUC						<u>\$73,397,774</u>			<u>\$87,867,086</u>

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

RESIDENTIAL Service Rate

Case No.: U-20718
Exhibit No.: A-16
Schedule: F4
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Witness: Shannon Burzycki

Line No.	(a) Monthly Usage (Mcf)	(b) Present Net Monthly Bill (\$/Month)	(c) Proposed Net Monthly Bill (\$/Month)	(d) Increase		(e) Percent (%)	(f) Proposed Unit Cost (\$/Mcf)
				Amount (\$/Month)	Percent		
1	0	\$13.00	\$14.75	\$1.75	13.46%		
2	2	23.54	25.95	2.42	10.27%		\$12.98
3	5	39.34	42.75	3.42	8.68%		8.55
4	7	49.87	53.96	4.08	8.19%		7.71
5	10	65.68	70.76	5.08	7.74%		7.08
6	15	92.02	98.76	6.75	7.34%		6.58
7	20	118.35	126.77	8.42	7.11%		6.34
8	25	144.69	154.77	10.08	6.97%		6.19
9	30	171.03	182.78	11.75	6.87%		6.09

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

SMALL GENERAL SERVICE Rate

Case No.: U-20718
Exhibit No.: A-16
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill (\$/Month)	Proposed Net Monthly Bill (\$/Month)	Increase		Unit Cost (\$/Mcf)
				Amount (\$/Month)	Percent (%)	
1	0	\$35.00	\$47.50	\$12.50	35.71%	
2	10	87.68	105.00	17.32	19.76%	\$10.50
3	25	166.69	191.25	24.56	14.73%	7.65
4	50	298.38	335.00	36.62	12.27%	6.70
5	75	430.07	478.75	48.68	11.32%	6.38
6	100	561.76	622.50	60.74	10.81%	6.22

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

MEDIUM GENERAL SERVICE Rate

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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill (\$/Month)	Proposed Net Monthly Bill (\$/Month)	Increase		Unit Cost (\$/Mcf)
				Amount (\$/Month)	Percent (%)	
1	0	\$35.00	\$135.00	\$100.00	285.71%	
2	10	\$87.68	\$189.39	101.71	116.01%	\$18.94
3	50	\$298.38	\$406.94	108.56	36.38%	8.14
4	100	\$561.76	\$678.88	117.12	20.85%	6.79
5	500	\$2,668.80	\$2,854.40	185.60	6.95%	5.71
6	1,000	\$5,302.60	\$5,573.80	271.20	5.11%	5.57

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

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LARGE GENERAL SERVICE Rate

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Monthly Usage (Mcf)	Present Net Monthly Bill (\$/Month)	Proposed Net Monthly Bill (\$/Month)	Increase		Unit Cost (\$/Mcf)
				Amount (\$/Month)	Percent (%)	
1	0	\$425.00	\$425.00	\$0.00	0.00%	
2	10	472.13	475.22	3.10	0.66%	\$47.52
3	50	660.64	676.12	15.48	2.34%	13.52
4	100	896.28	927.24	30.96	3.45%	9.27
5	250	1,603.20	1,680.60	77.40	4.83%	6.72
6	500	2,781.40	2,936.20	154.80	5.57%	5.87
7	750	3,959.60	4,191.80	232.20	5.86%	5.59
8	1,000	5,137.80	5,447.40	309.60	6.03%	5.45
9	1,250	6,316.00	6,703.00	387.00	6.13%	5.36
10	1,500	7,494.20	7,958.60	464.40	6.20%	5.31

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

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TRANSPORT Service Rate

Line No.	(a) Meter Class	(b) Monthly Usage (Mcf)	(c) Present Net Monthly Bill (\$/Month)	(d) Proposed Net Monthly Bill (\$/Month)	(e) Increase		(f)
					Amount (\$/Month)	Percent (%)	
1	TR-1 Transport	0	850.00	1,200.00	\$350.00	41.18%	
2	TR-1 Transport	500	1,208.58	1,581.93	373.35	30.89%	
3	TR-1 Transport	1,000	1,567.17	1,963.87	396.70	25.31%	
4	TR-1 Transport	2,000	2,284.34	2,727.74	443.40	19.41%	
5	TR-1 Transport	3,000	3,001.50	3,491.60	490.10	16.33%	
6							
7	TR-2 Transport	0	2,250.00	2,600.00	350.00	15.56%	
8	TR-2 Transport	1,000	2,652.12	3,054.92	402.80	15.19%	
9	TR-2 Transport	2,500	3,255.29	3,737.29	482.00	14.81%	
10	TR-2 Transport	5,000	4,260.58	4,874.58	614.00	14.41%	
11	TR-2 Transport	10,000	6,271.17	7,149.17	878.00	14.00%	
12							
13	TR-3 Transport	0	3,050.00	3,300.00	250.00	8.20%	
14	TR-3 Transport	2,500	3,999.72	4,381.22	381.50	9.54%	
15	TR-3 Transport	5,000	4,949.45	5,462.45	513.00	10.36%	
16	TR-3 Transport	10,000	6,848.89	7,624.89	776.00	11.33%	
17	TR-3 Transport	25,000	12,547.23	14,112.23	1,565.00	12.47%	
18	TR-3 Transport	50,000	22,044.45	24,924.45	2,880.00	13.06%	
19	TR-3 Transport	75,000	31,541.68	35,736.68	4,195.00	13.30%	

Schedule F4

**Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills**

AGGREGATED TRANSPORT Service Rate

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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Meter Class	Monthly Usage (Mcf)	Present Net Monthly Bill (\$/Month)	Proposed Net Monthly Bill (\$/Month)	Increase Amount (\$/Month)	Increase Percent (%)
1	Aggregated - Residential to Residential	0	\$34.50	\$36.25	\$1.75	5.07%
2	Aggregated - Residential to Residential	2	37.67	40.12	2.45	6.50%
3	Aggregated - Residential to Residential	5	42.44	45.93	3.50	8.24%
4	Aggregated - Residential to Residential	7	45.61	49.80	4.19	9.20%
5	Aggregated - Residential to Residential	10	50.37	55.61	5.24	10.41%
6	Aggregated - Residential to Residential	15	58.31	65.29	6.99	11.98%
7	Aggregated - Residential to Residential	20	66.24	74.98	8.73	13.18%
8	Aggregated - Residential to Residential	25	74.18	84.66	10.48	14.13%
9	Aggregated - Residential to Residential	30	82.11	94.34	12.23	14.89%
10						
11	Aggregated - Small to General Service - Small	0	56.50	69.00	12.50	22.12%
12	Aggregated - Small to General Service - Small	10	72.37	89.85	17.48	24.16%
13	Aggregated - Small to General Service - Small	25	96.18	121.13	24.96	25.95%
14	Aggregated - Small to General Service - Small	50	135.85	173.27	37.42	27.54%
15	Aggregated - Small to General Service - Small	75	175.53	225.40	49.87	28.41%
16	Aggregated - Small to General Service - Small	100	215.20	277.53	62.33	28.96%
17						
18	Aggregated - Small to General Service - Medium	0	56.50	156.50	100.00	176.99%
19	Aggregated - Small to General Service - Medium	10	72.37	174.24	101.87	140.76%
20	Aggregated - Small to General Service - Medium	50	135.85	245.21	109.36	80.50%
21	Aggregated - Small to General Service - Medium	100	215.20	333.91	118.71	55.16%
22	Aggregated - Small to General Service - Medium	500	850.00	1,043.55	193.55	22.77%
23	Aggregated - Small to General Service - Medium	1,000	1,643.50	1,930.60	287.10	17.47%
24						
25	Aggregated - Large to General Service - Large	0	446.50	446.50	0.00	0.00%
26	Aggregated - Large to General Service - Large	10	456.82	460.08	3.26	0.71%
27	Aggregated - Large to General Service - Large	50	498.11	514.39	16.28	3.27%
28	Aggregated - Large to General Service - Large	100	549.72	582.27	32.55	5.92%
29	Aggregated - Large to General Service - Large	250	704.55	785.93	81.38	11.55%
30	Aggregated - Large to General Service - Large	500	962.60	1,125.35	162.75	16.91%
31	Aggregated - Large to General Service - Large	750	1,220.65	1,464.78	244.13	20.00%
32	Aggregated - Large to General Service - Large	1,000	1,478.70	1,804.20	325.50	22.01%
33	Aggregated - Large to General Service - Large	1,250	1,736.75	2,143.63	406.88	23.43%
34	Aggregated - Large to General Service - Large	1,500	1,994.80	2,483.05	488.25	24.48%

Schedule F4

Michigan Public Service Commission
Michigan Gas Utilities Corporation
Comparison of Present and Proposed Monthly Bills

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CHOICE Service Rates

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Meter Class	Monthly Usage (Mcf)	Present Net Monthly Bill (\$/Month)	Proposed Net Monthly Bill (\$/Month)	Increase	
					Amount (\$/Month)	Percent (%)
1	Choice - Residential	0	\$13.00	\$14.75	\$1.75	13.46%
2	Choice - Residential	2	16.17	18.62	2.45	15.14%
3	Choice - Residential	5	20.94	24.43	3.50	16.70%
4	Choice - Residential	7	24.11	28.30	4.19	17.40%
5	Choice - Residential	10	28.87	34.11	5.24	18.16%
6	Choice - Residential	15	36.81	43.79	6.99	18.99%
7	Choice - Residential	20	44.74	53.48	8.73	19.52%
8	Choice - Residential	25	52.68	63.16	10.48	19.89%
9	Choice - Residential	30	60.61	72.84	12.23	20.17%
10						
11	Choice - General Service - Small	0	35.00	47.50	12.50	35.71%
12	Choice - General Service - Small	10	50.87	68.35	17.48	34.37%
13	Choice - General Service - Small	25	74.68	99.63	24.96	33.42%
14	Choice - General Service - Small	50	114.35	151.77	37.42	32.72%
15	Choice - General Service - Small	75	154.03	203.90	49.87	32.38%
16	Choice - General Service - Small	100	193.70	256.03	62.33	32.18%
17						
18	Choice - General Service - Medium	0	35.00	135.00	100.00	285.71%
19	Choice - General Service - Medium	10	50.87	152.74	101.87	200.26%
20	Choice - General Service - Medium	50	114.35	223.71	109.36	95.63%
21	Choice - General Service - Medium	100	193.70	312.41	118.71	61.29%
22	Choice - General Service - Medium	500	828.50	1,022.05	193.55	23.36%
23	Choice - General Service - Medium	1,000	1,622.00	1,909.10	287.10	17.70%
24						
25	Choice - General Service - Large	0	425.00	425.00	0.00	0.00%
26	Choice - General Service - Large	10	435.32	438.58	3.26	0.75%
27	Choice - General Service - Large	50	476.61	492.89	16.28	3.41%
28	Choice - General Service - Large	100	528.22	560.77	32.55	6.16%
29	Choice - General Service - Large	250	683.05	764.43	81.38	11.91%
30	Choice - General Service - Large	500	941.10	1,103.85	162.75	17.29%
31	Choice - General Service - Large	750	1,199.15	1,443.28	244.13	20.36%
32	Choice - General Service - Large	1,000	1,457.20	1,782.70	325.50	22.34%
33	Choice - General Service - Large	1,250	1,715.25	2,122.13	406.88	23.72%
34	Choice - General Service - Large	1,500	1,973.30	2,461.55	488.25	24.74%

MICHIGAN GAS UTILITIES CORPORATION

SUMMARY OF TARIFF CHANGES

Tariff			
<u>Sheet No.</u>	<u>Rule No.</u>	<u>Paragraph</u>	<u>Description of Changes</u>
A-6.00		Index	Updated Index to accommodate Medium General Service and Gas Demand Response.
A-12.00		Map	Updated Service Territory map.
C-13.00	C3.2	Curtailment of Gas Service	Changed letter "e)" to "c)"
C-20.00	C4	Centrally Metered Installations	Changed references of Centrally Metered Installations to Master Meter Systems per Michigan Gas Safety Guide.
C-20.01	C4	Centrally Metered Installations	Changed references of Centrally Metered Installations to Master Meter Systems per Michigan Gas Safety Guide.
C-21.00	C4	Centrally Metered Installations	Moved language to C-20.01
C-28.00	C8	General Provisions	Changed references of Centrally Metered Installations to Master Meter
	C8.2	Adequacy and safety of installation	Included language clarifying installations will be approved in accordance with all applicable codes and standards.
C-29.00	C8	Change in Customer's Requirements	Removed reference to Rule C7.5, "Company's Installation".
C-30.00	C8	Measurement of Gas Service	Removed reference to Rule C7.5, "Company's Installation".
C-34.00 - C-35.00	C11	Customer Attachment Program	Clarified language to include Small General Service and Medium General Service
C-36.00	C11	Customer Attachment Program	Updated Carrying Cost Rate per proposed rate case
C-37.00	C11	Customer Attachment Program	Updated Discount Rate per proposed rate case
C-38.00 - C-45.00	C11	Customer Attachment Program	Updated CAPs
D-1.02 - D-1.03	D2	Supplemental Charges	Removed TCJA Credits
D-1.04 - D-1.07	D2	Supplemental Charges	Added MRP Surcharge Rider

MICHIGAN GAS UTILITIES CORPORATION

SUMMARY OF TARIFF CHANGES

Tariff			
<u>Sheet No.</u>	<u>Rule No.</u>	<u>Paragraph</u>	<u>Description of Changes</u>
D-6.00	D4	Rate	The Customer, Distribution and Acquisition Charges have been updated per the proposed rate design.
D-8.00 - D-16.00	D5 - D7	Rate	Reorientation of pages, addition of Medium General Service, Customer, Distribution and Acquisition Charges have been updated per the proposed rate design.
D-17.00	D8	Rate	Removed Residential Rate. The Customer, Distribution and Acquisition Charges have been updated per the proposed rate design.
D-18.00 - D-25.00	D9 - D12	Rate	Added Gas Demand Response Program
E-5.00 - E-6.00	E2	Nominations, Accounting & Controls	Former name and link of electronic bulletin board have been removed. New abbreviated reference for electronic bulletin board (EBB). Adding language that nomination deadlines must follow NAESB Standard.
E-12.00	E5.1	Availability	Eliminated the specification of two hours.
E-13.00	E5.3	Aggregation of Accounts Option	Revised sheet references.
E-13.00	E5.4	Rates and Charges	Added monthly telemetering charge for each subsidiary account to the table. Added usage break points.
E-14.00	E5.4	Rates and Charges	Added MRP Surcharge Rider.
E-14.00	E5.6	Supplemental Charges	Revised sheet references.
E-16.00	E5.8	Daily Balancing Service	Added language for Supplier and customer notification.
F-2.00	F1	General Provisions	Under Daily Delivery Obligations monthly has been changed to daily. Language regarding delivery requirements has been updated.
F-3.00	F1	General Provisions	Under Nominations adding language that nomination deadlines must follow NAESB Standard.
F-6.00 - F-9.00	F2	Customer Protections	Added Medium Commercial references and language and usage break points.
F-10.00	F3	Solicitation Requirements	Added Medium Commercial references and language and usage break points.
F-11.00	F3-F4	Solicitation Requirements	Added Medium Commercial references and language and usage break points.

Continued From Sheet No. A-5.00

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SECTION D RATE SCHEDULES

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D2. SUPPLEMENTAL CHARGES	D-1.00
D3. GAS COST RECOVERY FACTORS	D-2.00
D4. RESIDENTIAL RATE	D-5.00
D5. SMALL GENERAL SERVICE RATE	<u>D-8.00</u>
D6. ~~SMALL~~ <u>MEDIUM</u> GENERAL SERVICE RATE	D-11.00
D7. LARGE GENERAL SERVICE RATE	D- ~~1411~~ .00
D8. GAS LIGHTING RATE	D- ~~1715~~ .00
<u>D9. RESIDENTIAL GAS DEMAND RESPONSE</u>	<u>D-18.00</u>
<u>D10. SMALL GENERAL SERVICE GAS DEMAND RESPONSE</u>	<u>D-20.00</u>
<u>D11. MEDIUM GENERAL SERVICE GAS DEMAND RESPONSE</u>	<u>D-22.00</u>
<u>D12. LARGE GENERAL SERVICE GAS DEMAND RESPONSE</u>	<u>D-24.00</u>

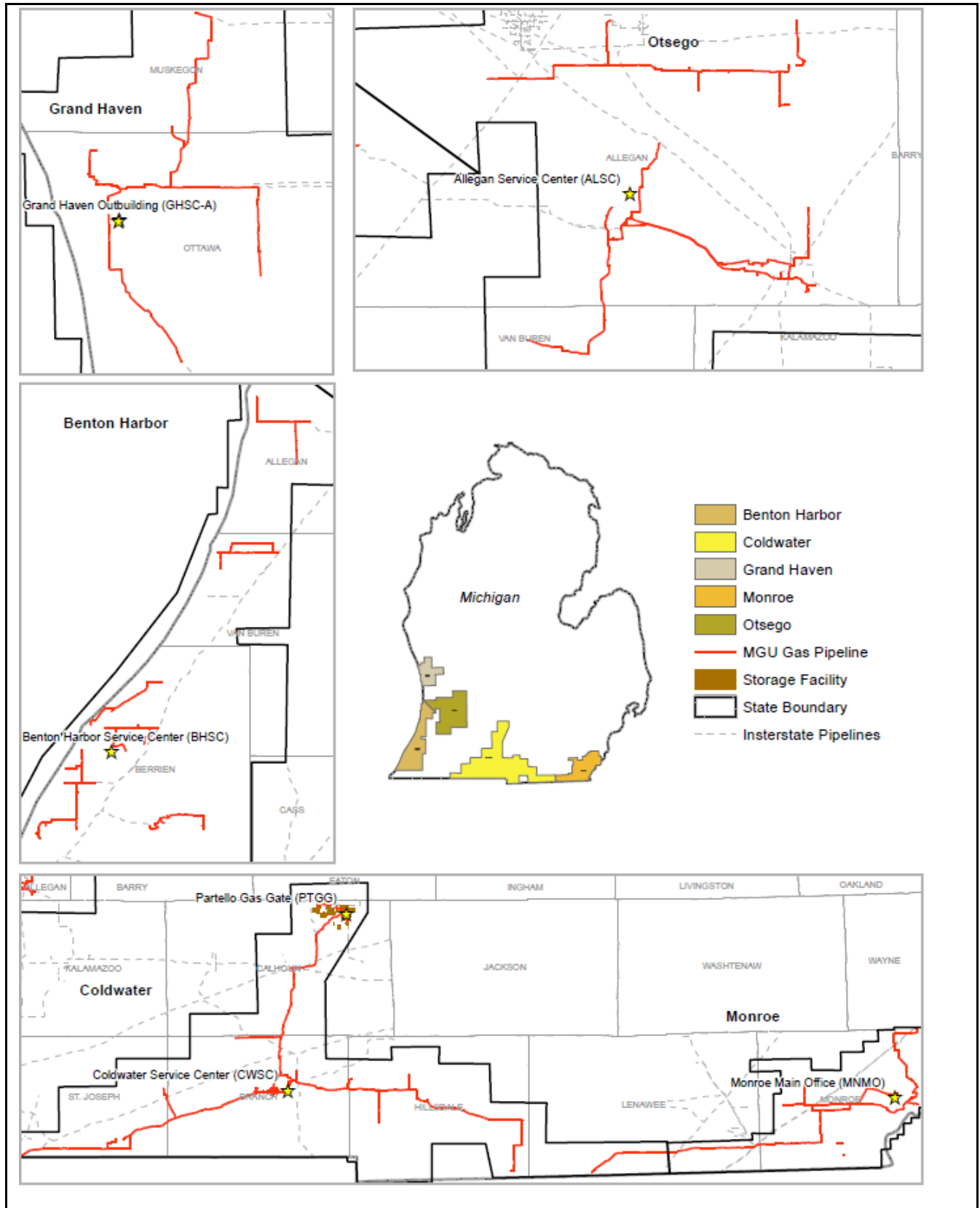
SECTION E GAS TRANSPORTATION SERVICE

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E1. GAS TRANSPORTATION SERVICE RULES	
E1.1 General Provisions and Definitions	E-1.00
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E1.3 Possession of Gas	E-4.00
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Continued on Sheet No. A-7.00

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Milwaukee, Wisconsin



Continued From Sheet No. C-12.03

C3.2 Curtailment of Gas Service (Contd.)

(vi) Penalties for Violation of an OFO (Contd.)

ec) Nominations and Waivers:

The Company reserves the right to reject any nomination on a particular pipeline that does not meet its operational requirements. Rejecting or confirming nominations by the Company does not release the transportation customer/supplier from its obligations under the tariff. Failure to pay an unauthorized usage or excess delivery charge when due shall subject the customer to termination of gas service.

The Company reserves the right to waive, on a non-discriminatory basis, any unauthorized usage charge non-pipeline penalty for violating an OFO if such penalty is the result of actions beyond the customer's control. Penalties collected by the Company will be credited to the Company's booked GCR cost of gas sold.

Continued on Sheet No. C-13.01

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Continued From Sheet No. C-19.00

C4. APPLICATION OF RATES (Condt.)

C4.3 ~~Centrally Metered Installations~~ Master Metered Systems.

A ~~centrally metered installation~~ master meter system is one that meets all of the following conditions:

- (a) The ~~complex~~ system is served by a single meter installation: and
- (b) The fuel lines are ~~buried~~ above or below ~~underground~~ from the central meter installation to the location at which each fuel line enters each building or mobile home at its outside and extend from the meter to a point at which each fuel line terminates at outside utilization equipment or at the building wall (hereby called "termination points"); and
 - i. ~~Where the complex consists of two or more separate buildings, such as apartments, multifamily dwellings, dormitories or similar type buildings are supplied with gas and at least two buildings so supplied contain four or more living units, or~~
 - ii. ~~Where the complex consists of mobile homes, four or more mobile homes used as living units are supplied with gas.~~
- (c) ~~A centrally metered installation may also be an individual building served by a single meter installation where gas is provided to multiple living units~~ Three or more said termination points exist on the fuel line system;
- (d) The system serves a third party who routinely consumes gas.

The customer served with a ~~centrally metered installation~~ master meter system must enter into an inspection and maintenance contract with the Company covering such customer-owned underground gas distribution system(s). The underground gas distribution system(s) downstream of the meter shall be paid for and owned by the customer.

The installation of the underground gas distribution system(s) from ~~the central metering~~ master meter to each termination point will be ~~to the location at which the gas line(s) enter(s) the customer's building or any extensions or modifications thereto, including the initiation of gas service to each building, will be~~ the responsibility of the Company in accordance with the Company's design, installation, operation and maintenance procedures for underground pipe system(s) and in accordance with the Standards of the Michigan Gas Safety Standards.

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In Case No.: U-20718

Continued From Sheet No. C-20.00

C4.3 Centrally Metered Installations Master Metered Systems (Condt.)

Pursuant to R460.20335(3) ~~T~~he charge to the customer for the installation of or addition to the underground gas distribution system(s), or any extensions or modifications thereto, will be at the Company's cost plus appropriate overheads.

With respect to customer-owned underground gas distribution system(s), pursuant to R460.20335(4) the customer will pay for the cost of inspection and maintenance of such underground gas distribution system(s) downstream of the meter at costs to be determined by the Company under terms agreed to in the Contract for Maintenance of Customer-Owned Underground Gas Distribution Systems as filed with the Michigan Public Service Commission. Extensions or modifications to customer-owned underground gas distribution system(s) shall be made only in accordance with the Contract for Maintenance of Customer-Owned Underground Gas Distribution Systems and shall be made by the Company.

Failure of a ~~centrally~~ master metered customer to enter into and comply with the Contract for Maintenance of Customer-Owned Underground Gas Distribution Systems, as above described, shall be cause for cessation of gas service which will not be reinstated or installed until such contract has been executed and complied with.

C4.4 Redistribution of gas service.

Gas will not be supplied to any customer except for the customer's own use or for the use of the customer's tenants in the building or premise supplied with gas under the service agreement between the Company and the customer. Gas will not be supplied under a filed rate of this rate schedule for submetering or resale by or to any owner, tenant or occupant of any premises. A customer shall not submeter, resell or otherwise dispose of any gas supplied to him under any filed rate; except that a customer of the Company may redistribute such gas to his tenants in the premises supplied when the customer is supplied under a filed rate which does not prohibit such redistribution, and provided that no specific charge is made therein.

C4.5 Notice of change in ownership of occupancy of premises.

Immediately upon sale, lease or any other change in occupancy of the premises or any portion thereof supplied under an agreement for service, the customer shall give written notice to the Company of such change.

Continued on Sheet No. C-21.00

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Continued From Sheet No. C-20.00

~~**C4.3 Centrally metered installations. (Contd)**~~

~~Failure of a centrally metered customer to enter into and comply with the Contract for Maintenance of Customer-Owned Underground Gas Distribution Systems, as above described, shall be cause for cessation of gas service which will not be reinstated or installed until such contract has been executed and complied with.~~

~~**C4.4 Redistribution of gas service.**~~

~~Gas will not be supplied to any customer except for the customer's own use or for the use of the customer's tenants in the building or premise supplied with gas under the service agreement between the Company and the customer. Gas will not be supplied under a filed rate of this rate schedule for submetering or resale by or to any owner, tenant or occupant of any premises. A customer shall not submeter, resell or otherwise dispose of any gas supplied to him under any filed rate; except that a customer of the Company may redistribute such gas to his tenants in the premises supplied when the customer is supplied under a filed rate which does not prohibit such redistribution, and provided that no specific charge is made therein.~~

~~**C4.5 Notice of change in ownership of occupancy of premises.**~~

~~Immediately upon sale, lease or any other change in occupancy of the premises or any portion thereof supplied under an agreement for service, the customer shall give written notice to the Company of such change.~~

C5. CUSTOMER RESPONSIBILITIES

C5.1 Access to premises.

The Company shall have the right of access to its meter or appurtenances upon the customer's premises at all reasonable times for the purpose of reading meters, of inspecting or repairing its meters and appurtenances, or of removing its property, or for any other proper purpose. All authorized employees of the Company are provided with proper identification.

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C8. METERING CUSTOMER EQUIPMENT AND BILLING

C8.1 General provisions.

The customer shall furnish and maintain all piping and equipment beyond the point of service termination at his own expense, except as expressly provided under Rule C4.3, "~~Centrally metered installations~~ Master Meter System".

C8.2 Adequacy and safety of installation.

The Company shall not be required to supply gas service until the customer's installation shall have been approved by the authorities, in accordance with all applicable codes and standards, having jurisdiction over the same; and the Company further reserves the right to withhold its service, or discontinue service, whenever such installation or part thereof is deemed by the Company to be unsafe, inadequate or unsuitable for receiving the Company's service.

C8.3 Repairs - leakage of gas.

All repairs to the customer's piping and equipment shall be made by the customer, and he shall maintain the piping and equipment in the condition required by the authorities having jurisdiction and by the Company. The customer shall give immediate notice to the Company of the indication of any gas leakage.

C8.4 Back pressure and suction.

When the nature of the customer's utilization equipment is such that it may induce back-pressure or suction in the piping system carrying the Company's gas, suitable protective devices, subject to inspection and approval by the Company, shall be furnished, installed and maintained by the customer to protect the customer and the Company's facilities therefrom.

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C8. METERING CUSTOMER EQUIPMENT AND BILLING (Condt.)

C8.5 Inspection of installation.

The Company will not establish gas service to any customer until a representative of the Company has made a test of all gas appliances by observing the meter(s) when all appliances are shut off and gas pressure is on such piping and appliances and finds that no gas passes the meter(s) under such conditions.

If all appliances are shut off and gas passes through the meter(s), the Company will notify the customer of that fact and gas service will not be established until such defect is repaired or corrected.

The Company may require an authorized representative of the customer to perform an "Air Test" on the meter in accordance with the National Fuel Gas Code Rule 4.1.4 - "Air Testing of Customer Lines".

Nothing in this rule shall be construed to make the Company liable for the installation, maintenance or use of piping or appliances owned by the customer beyond the making of the test above required; nor shall the Company be held liable for any continuing duty of inspection of piping or appliances, except as expressly provided under Rule C4.3, "Centrally metered installations".

C8.6 Changes in customer's requirements.

The customer shall give the Company reasonable advance notice in writing of intention to increase materially his load so that adequate facilities may be provided.

When there is a change in the customer's requirements for gas supply or a change by the customer from one filed rate to another, or when the customer includes in his requirements any service theretofore supplied to him or to others under another agreement or agreements for service, the customer shall make such changes and alterations in the piping, service equipment, meter equipment and appurtenances and other parts of the customer's installation as may be necessary to enable the Company to furnish safe and adequate service and to measure the gas thereafter to be supplied through a single meter or through the number of meters which the Company may elect to install ~~as provided under Rule C7.5, "Company's Installation"~~.

Such changes and alterations shall be governed by the requirements applying to new installations.

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C8.7 Measurement of gas service.

Bills will be based upon the registration of the Company's meters except as otherwise provided in these Rules, Regulations and Rate Schedules.

The rates contained in these Rules, Regulations and Rate Schedules apply to the quantities of gas registered by each individual meter for the billing period for which the meter may be read. A single meter shall not supply more than one customer. When the Company, ~~pursuant to provisions of Rule C7.5,~~ installs two or more meters on the same premises to serve a single customer, the consumption registered by such meters shall be consolidated and the rates under which service is taken applied to the total consumption.

C9. GAS COST RECOVERY CLAUSE

C9.1 Applicability of clause.

All rates for gas service, unless otherwise provided in the applicable rate schedule, shall include a Gas Cost Recovery Factor to allow the Company to recover the booked costs of gas sold by the Company if incurred under reasonable and prudent policies and practice.

C9.2 Booked cost of gas sold.

- (a) Booked cost of gas sold as used in this rule includes the following as expensed on the books of the Company:
 - (i) Interstate Purchases: Cost for gas service.
 - (ii) Intrastate Purchases: Costs for gas service incurred pursuant to all contracts on file with the Michigan Public Service Commission.
 - (iii) Company Produced Natural Gas: Costs which vary with volume produced.
 - (iv) Company Produced Substitute Natural Gas: Costs for feedstock used to produce substitute natural gas.
 - (v) Liquefied Petroleum Air Gas: Costs for propane used to produce a propane-air gas mixture.
 - (vi) Storage Gas: Net costs of gas injected and withdrawn from underground storage facilities.
 - (vii) Purchases From Other Michigan Utilities: Costs for gas service pursuant to contracts approved by the appropriate regulatory body.
 - (viii) Supplier Refunds and Credits: Refunds and credits from suppliers in the period realized.
 - (ix) Hedging costs.
 - (x) OFO penalties and Choice Supplier Failure Fees.

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C11. CUSTOMER ATTACHMENT PROGRAM

(1) Purpose

The Company proposes to make extension of its gas mains and/or service lines from time to time, at its own cost, to serve applicants whose requirements will not disturb or impair the service to prior users or will not require an expenditure out of proportion to the revenue obtainable there from.

The Company reserves the right to delay or deny a request for service under this rule, if fulfilling such a request could, in the Company's opinion, create conditions potentially adverse to the Company or its customers. Such conditions may include, but are not limited to, safety issues, system operating requirements or capital constraints. The provisions under this Rule are in addition to the existing rules and tariffs for customer gas service.

(2) Customer Contribution

A Customer Contribution shall be required equal to the Connection Fee plus any applicable Fixed Monthly Surcharge plus any Excessive Service Line Fee. The Connection Fee is not considered in the CAP model when calculating the Fixed Monthly Surcharge or Excessive Service Line Fee.

(3) Payment of Customer Contribution

For customers other than land developers, builders, Transportation customers, ~~and~~ those designated as **Small General Service, Medium General Service and** Large General Service, the Customer Contribution shall be paid as follows:

The Connection Fee and the Excessive Service Line Fee are payable in lump sum at the time the service agreement is executed by the customer. The Connection Fee is non-refundable. The Excessive Service Line Fee is refundable if the service line has not been installed. If the service line has been installed, the Excessive Service Line Fee is non-refundable. The Fixed Monthly Surcharge shall be payable monthly throughout the surcharge period. The Fixed Monthly Surcharge will commence on the date that the Company installs the meter. The customer may at any time elect to pay off the remaining Fixed Monthly Surcharge balance with a lump sum payment equal to the present value of the remaining monthly payments. If the present value of the Fixed Monthly Surcharge is less than \$200.00, the Company may require the customer to make a lump sum payment. The Fixed Monthly Surcharge is assessed to the property served such that any subsequent customer requesting gas service at the property address, once notified by the Company of the amount and duration of such surcharge, shall be liable for the Fixed Monthly Surcharge. Such notification may be verbal, written or in the form of a bill which includes the Fixed Monthly Surcharge. Failure of sellers, agents, lessors or other non-company parties to notify a customer of the Fixed Monthly Surcharge shall not relieve the customer's obligation to pay the Fixed Monthly Surcharge. Failure by the customer to timely pay the Fixed Monthly Surcharge shall result in the discontinuation, termination or denial of natural gas service.

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C11. Customer Attachment Program (Contd)

(3) Payment of Customer Contribution (Contd)

For land developers, builders, Transportation customers, ~~and~~ those customers designated as Small General Service, Medium General Service and Large General Service, the Customer Contribution shall be required in a non-refundable lump sum payment in advance of the facility expansion.

(4) Connection Fee

The Connection Fee is equal to \$200.00. The Connection Fee is not considered in the CAP Model when calculating the Fixed Monthly Surcharge or Excessive Service Line Fee.

For customers requesting a multiple metered installation, the Connection Fee shall be \$100 for each additional account.

(5) Excessive Service Line Fee

The Excessive Service Line Fee will be assessed to a customer whose service line requirement is in excess of the Service Line Limit. The Service Line Limit for an individual service line shall be equal to the point at which the cost of the customer's service requirements are greater than the allowance based on the Cost Of Service Model. The Company reserves the right to use a different Service Line Limit for different categories of customers. In calculating the average service line length for a project containing more than one customer, the maximum length of each service line to be included in the calculation is the Service Line Limit for a primary residential home.

The Company, in its sole discretion, may waive the excessive service line fee or extend the service line limit for all attaching parties based on the economics of a proposed project. Any such waiver or extension shall not be effective unless provided in writing by the Company.

(6) Fixed Monthly Surcharge

A Fixed Monthly Surcharge (Surcharge) will be calculated for each Customer Attachment Project (Project). The Surcharge will recover the Revenue Deficiency anticipated from the proposed Project. The Surcharge is calculated such that the present value of the anticipated Surcharges collected from the Project will equal the net present value Revenue Deficiency. The Surcharge will be recoverable over a predetermined time period, not to exceed ten years. The Company will be responsible for determining the appropriate Surcharge time period. The Surcharge will be a fixed dollar amount for all customers within the Project and will expire on the same date for all customers within the Project, regardless of when the surcharge was initially assessed to the customer. The Surcharge and lump sum payment referenced in C-11.(3) will not be subject to adjustment, reconciliation or refund. A customer who attaches to a Project after the surcharge period has expired or a customer whose proposed attachment was beyond the scope of the original a Project, will be treated as a separate Project.

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C11. Customer Attachment Program (Contd)

(7) Customer Attachment Project

A Project may consist of a single customer, requiring only the installation of a service line and meter, or may consist of numerous customers requiring the installation of mains, service lines and meters. A Project will generally be defined as a customer or group of customers that may be served from the contiguous expansion of new distribution facilities.

(8) Revenue Deficiency

A discounted Cost of Service Model (Model) will be used to calculate the Net Present Value (NPV) Revenue Deficiency anticipated from a Project. The Model will use the expected incremental revenues and incremental costs associated with the Project for each year of a twenty year period. From this information an annual net revenue excess or deficiency will be calculated. The annual net revenue excess or deficiency will be discounted and summed to determine the NPV revenue deficiency of the Project. If the NPV revenue deficiency is negative, the discounted revenues exceed the discounted costs, then a NPV revenue deficiency of zero will be used.

(9) Model Assumptions:

Incremental Revenues:

The Incremental Revenues will be calculated based on current rates and a forecast of the timing and number of customer attachments as well as the customers' annual consumption levels.

Incremental Costs:

(i) Carrying Cost Rate

The Carrying Cost Rate will be based on the weighted rate of debt, equity and associated taxes. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. The Carrying Cost Rate is equal to ~~10.08%~~ 8.68%.

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C11. Customer Attachment Program (Contd)

(ii) Plant in Service

Plant in Service shall reflect the Company's estimated cost to construct distribution mains, customer service lines, meters and pressure regulators or regulating facilities for the Project. The timing of the facility investment, primarily service lines, will correspond with the projected timing of the customer attachments.

The facility investment for an individual customer service line will be limited to the greater of 400 feet or 150% of the average length of all service lines within the Project.

(iii) Carrying Costs

The Carrying Costs will be the product of the average of beginning and end-of-year net plant, Plant in Service minus accumulated depreciation minus deferred taxes, multiplied by the Carrying Cost Rate, noted in paragraph 1 above.

(iv) Depreciation

Depreciation expense will be the product of Plant in Service multiplied by the appropriate prescribed depreciation rates approved for the Company.

(v) Property Taxes and Other Operating Expenses

Property taxes will be the product of Plant in Service multiplied by the Company's average property tax rate. All other incremental operating expenses will be included as identified. Incremental O&M will at a minimum include a proportional cost for monthly meter reading, billing and mailing.

(vi) Discount Rate

The Discount Rate will be a weighted rate of long-term debt and common equity. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. Based on the Company's rate order in Case No. U-20718 dated ~~December 11, 2015~~, the Discount Rate is equal to ~~7.44%~~6.95%.

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C11. Customer Attachment Program (Contd)

(10) Customer Attachment Project Areas

All gas sold in any area specifically listed below is subject to the following Customer Attachment Project (CAP) charges. CAP areas and charges shall be added to or removed from the list from time to time by the Company.

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X324	My Road	\$44.06	December 2021
X325	48th & Cross Ln	\$22.05	July 2021
X327	N. Cedar & 104th	\$22.57	August 2021
X328	Eidson & Rocky Weed	\$24.09	August 2021
X329	County Road 380	\$16.03	April 2021
X330	Samaria & Geiger	\$17.85	August 2021
X331	16th Ave.	\$20.52	September 2021
X332	106th & Miller Rd.	\$23.24	September 2021
X333	Dixon Rd.	\$25.43	August 2021
X334	S. Pleasant Lake	\$23.30	September 2021
X335	Stout Rd.	\$60.65	October 2021
X336	Tiburon	\$25.74	December 2021
X337	Mechanic Drive	\$16.13	December 2021
X338	478 Otis Rd.	\$39.01	October 2021
X339	92-4th Street	\$16.68	August 2022
X340	Langland farms Garfield	\$25.00	June 2022
X341	156TH ST at Lake Michigan Drive	\$16.95	August 2022
X342	Rabbit River	\$29.75	July 2022
X343	Tulip Tree Lane	\$32.91	September 2022
X344	344 34th st	\$27.47	September 2022
X345	128th & Buchanan	\$30.43	August 2022
X347	Marshall Rd	\$10.17	September 2022
X348	Baseline at 72nd	\$21.19	September 2022
X349	8 Mile	\$64.67	October 2022
X350	Clegg Road, Whiteford	\$30.77	November 2022
X351	Pierce St	\$37.28	October 2022
X352	W. Channel Drive	\$26.80	October 2022
X353	State Road	\$17.12	December 2022

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C11. Customer Attachment Program (Contd)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X354	124th CP	\$19.88	May 2023
X355	Birchwood Dr	\$32.98	December 2022
X356	Cleo Dr	\$24.93	August 2022
X357	91 - 104th	\$29.82	August 2023
X359	Buchanan & Harmony	\$26.06	September 2023
X360	Bankers	\$16.37	August 2023
X361	Scheick	\$31.47	September 2023
X362	Otter Rd	\$29.58	June 2023
X363	Burns	\$33.99	September 2023
X364	108th @ Sleeper	\$16.00	November 2023
X365	Coloma Road	\$15.73	November 2023
X366	Linco	\$24.67	December 2023
X367	My Road	\$22.86	September 2023
X368	Cheyenne Tr & 120th	\$37.03	June 2024
X369	Samaria Rd. in Bedford TWP	\$28.22	October 2023
X370	Nye Rd	\$34.69	October 2023
X371	Strasburg S Otter & Hubbard	\$34.48	March 2024
X372	M140	\$12.66	May 2024
X373	Plum	\$18.26	January 2024
X374	Airport Road	\$14.82	January 2024
X375	Scottdale	\$16.59	July 2024
X376	72nd s of 16	\$29.59	May 2024
X377	2nd Ave	\$32.39	June 2024
X378	California	\$26.26	July 2024
X382	114th Ave.	\$30.00	September 2024
X383	Date Rd	\$22.89	July 2024
X386	102nd from 13th to 15th	\$25.88	July 2024
X387	108th - Allegan	\$30.00	August 2024
X388	Kendra Rd	\$31.02	July 2024
X389	Ferris St.	\$43.12	June 2024
X390	Territorial Rd	\$20.08	September 2024
X392	Hagar Shore II	\$33.43	October 2024

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<u>CAP No.</u>	<u>CAP Name</u>	<u>CAP Charge Per Month</u>	<u>Last Billing Month For Surcharge</u>
X393	Lake Allegan North	\$26.64	June 2025
X395	Kelly	\$33.90	July 2024
X396	34th North of 138th	\$32.03	October 2024
X397	56th Street	\$22.02	September 2024
X398	Echo Rd	\$12.00	August 2024
X399	112th & Brielle	\$32.75	March 2025
X400	Reading Rd	\$37.91	November 2024
X401	Tawas Drive	\$14.98	September 2024
X402	Finzel Road	\$45.25	August 2024
X403	E Randall	\$31.50	December 2024
X404	Carleton West Project	\$58.83	November 2024
X405	Big Hill Rd.	\$23.56	December 2024
X406	Wolcott St.	\$8.84	October 2024
X408	Ferndale Road	\$18.30	December 2024
X409	119th	\$28.27	October 2024
X410	Benton Center	\$19.60	November 2025
X411	13th Ave Private Drive	\$15.90	July 2020
X412	Wilson	\$14.96	April 2020
X413	Coloma Road II	\$24.15	January 2026
X414	Kay Drive	\$14.15	December 2025
X415	Division Drive	\$260.22	August 2024
X416	Chabot/Off Riverside	\$18.11	March 2025
X417	13865 Carleton West Rd	\$52.12	November 2024
X418	Miller Drive	\$14.64	December 2024
X419	Suder & Substation	\$37.57	November 2024
X420	Wells & Central	\$25.41	November 2024
X421	Laplaisance	\$26.32	December 2024
X422	36th - Dorr	\$45.16	December 2024
X423	Country Lane Main	\$32.27	December 2024
X424	Washington	\$15.63	December 2024
X425	Lake Chapin	\$25.01	January 2025
X426	Hull Rd.	\$35.65	May 2025

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<u>CAP No.</u>	<u>CAP Name</u>	<u>CAP Charge Per Month</u>	<u>Last Billing Month For Surcharge</u>
X427	War, Buhl, Mentel	\$46.15	October 2025
X428	Stanley Dr	\$21.51	June 2025
X429	68th St	\$19.55	July 2025
X430	58th St	\$18.94	July 2025
X431	Taylor Street	\$15.68	August 2025
X432	Pershing Drive	\$25.39	July 2025
X433	Black River Rd	\$22.27	August 2025
X434	Waldron	\$15.99	December 2025
X435	CR380/69th	\$24.76	August 2025
X436	Territorial #2	\$16.57	December 2025
X437	Tudor Rd	\$24.45	September 2025
X438	Bankers/Cambria	\$42.69	December 2024
X440	S Fremont Rd	\$14.72	May 2025
X441	Onway Dr (E of Whiteford Rd.)	\$20.10	May 2025
X442	Chabot/Off Broderick	\$29.38	August 2025
X443	E. Beach	\$20.73	December 2025
X444	Walnut	\$21.23	August 2025
X446	Ida Center (W of Lewis Ave)	\$41.88	June 2025
X447	106th Ave & 6th St	\$5.85	September 2025
X448	Ida West W of Summerfield	\$38.70	June 2025
X449	Ida West E of Gloff	\$12.81	July 2025
X450	E Substation Rd	\$49.48	June 2025
X451	Brewer Rd	\$9.01	June 2025
X453	Long Lake Road	\$51.28	January 2026
X455	Consear Rd	\$35.39	April 2026
X456	Lincoln St Pvt Drive	\$38.51	November 2025
X457	Tudor Rd. #2	\$37.22	November 2025
X459	73rd 1/2 Street	\$18.85	March 2026
X460	Erie	\$21.10	September 2026
X461	Lime Lake	\$18.53	October 2026
X462	Edgewood Rd-W of M125	\$35.80	April 2026
X463	Handy Dr -W of Spaulding	\$18.30	July 2026

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X465	Samaria Rd-W of Whiteford	\$40.09	April 2026
X466	Secor and Todd-S of Ida Cntr	\$45.12	August 2026
X467	Summerfield Rd-N of Cortz	\$39.51	May 2026
X468	Whiteford-W of Temperance	\$48.42	June 2026
X470	Lincoln at Carolyn	\$26.74	April 2026
X471	Hillandale	\$22.26	May 2026
X472	Blue Star	\$17.85	July 2021
X473	Rich St & 128th Ave	\$30.25	June 2026
X474	Grand Mere	\$41.74	July 2026
X475	TULIP	\$22.29	September 2027
X477	Fox Hollow Dr	\$12.21	June 2026
X478	Tantre Drive	\$25.32	August 2026
X479	Garfield Rd	\$19.39	September 2026
X480	Stumpmier Road	\$24.10	November 2026
X481	Blue Star @ Private Dr	\$19.02	June 2027
X482	Briar Hill Road	\$19.88	May 2027
X483	1167 102nd	\$5.94	October 2026
X484	11360 168th	\$95.62	November 2026
X485	13th & 130th	\$20.00	March 2027
X486	129th Ave	\$20.00	March 2027
X487	Maxwell Rd.	\$97.23	November 2026
X488	Jakes Alley	\$60.09	November 2026
X489	136th Ave and 14th Ave	\$30.00	March 2027
X490	Kruse Rd	\$26.49	July 2027
X491	Prince Street	\$17.08	April 2022
X492	Suder Rd, Lotus Dr.	\$49.99	September 2027
X493	Victory Road	\$39.22	August 2027
X494	Hallett Rd	\$28.20	October 2027
X495	Melvin & 44th	\$40.35	October 2027
X496	N Hillsdale Rd. at Moore	\$19.05	October 2027
X497	Laplaisance & Lavigne Rd	\$49.45	August 2027
X498	Lake Forest Path	\$24.91	November 2027

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<u>CAP No.</u>	<u>CAP Name</u>	<u>CAP Charge Per Month</u>	<u>Last Billing Month For Surcharge</u>
X499	Whisper Ln & CT	\$29.53	October 2027
X500	Dale Ct.	\$20.93	October 2027
X501	Niebles Landing	\$9.07	October 2027
X502	Ida West Road	\$48.38	December 2027
X503	Burr Oak Rd. Bronson	\$21.42	January 2028
X504	26th Street - Monterey Twp.	\$20.00	May 2028
X505	Morocco Rd	\$32.12	May 2028
X506	Baseline at 71 1/2 St.	\$19.52	July 2028
X507	Whiteford Center Rd.	\$31.52	July 2028
X508	Swartz Rd	\$36.98	July 2028
X509	Donnell & Bennett	\$11.58	July 2028
X510	7th Street	32.76	August 2028
X511	13th St off 102nd	19.41	July 2028
X512	Pierce @ Carolyn	\$29.38	August 2028
X513	Farr Rd. W	57.52	August 2028
X514	Carter/Anabell Roads	\$64.39	September 2028
X515	137th E of 30th	51.74	September 2028
X516	Holden Rd	\$24.94	September 2028
X517	Browntown Rd	\$27.46	October 2028
X518	Euclid Street	\$13.70	October 2028
X519	Moccasin Trail	\$19.20	October 2023
X520	E. Creek	\$47.83	November 2028
X521	Rich St W of M231	\$39.24	November 2028
X522	N Telegraph - Newport/I275	\$58.81	December 2028
X523	Bercaw - 8 Mile	\$19.95	November 2028
X524	Post Rd	\$20.00	February 2029
X525	Stutzman Farms	\$20.85	April 2029
X526	Olnhausen	\$18.26	April 2029
X527	Meanwell Rd	\$38.21	May 2029
X528	Edgewood Rd	\$21.28	May 2029
X529	Beach Drive	\$10.49	June 2024
X530	Lost Peninsula Phase 2	\$31.82	July 2029

Continued on Sheet No. C-44.00

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C11. Customer Attachment Program (Contd)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X531	Wood Rd/Minx Rd	30.37	July 2029
x532	Blatchford & Paw Paw Rd.	\$35.00	August 2029
X533	8th st n of 146th	\$59.51	July 2029
X534	Stadler & Doty Rd.	\$35.22	August 2029
X535	Johnson Rd	\$36.43	September 2029
X536	Pier Rd	\$35.33	August 2029
X537	South Stoney Creek Rd.	\$40.75	September 2029
X538	California @ Ott	\$35.01	September 2029
X539	S. Telegraph Rd.	\$34.58	September 2029
X540	E. Stein Rd.	\$50.76	October 2029
X541	Carter Rd	\$40.86	October 2029
X542	Orchard Trail	\$44.47	December 2029
X543	Rockey Weed @ Ann Ct	\$35.40	January 2030
X544	Browntown Phase 2	\$36.16	January 2030
X545	Niles Rd	\$35.00	March 2030
X546	Dunks Rd	\$35.22	March 2030
X547	50TH ST CAP	\$65.44	June 2030
X548	Kelly Rd	\$45.05	April 2030
X549	EGGERT RD	\$50.55	May 2030
X550	Rosehill Rd	\$31.90	June 2030
X551	Reinhardt Rd	\$36.30	June 2030
X552	Maxwell Rd	\$48.85	June 2030
X553	463 & 467 6TH STREET	\$31.70	July 2030
X554	BROADWAY	\$17.65	July 2023
X555	M86 Main	\$32.21	July 2030
X556	Meanwell/Ida West Rd	\$27.72	July 2030
X557	Tulip Street	\$18.02	August 2030
X558	Lavign/S Otter Creek	\$35.00	September 2030
X559	CR 384	\$25.11	September 2030
X560	Port Creek	\$57.83	September 2030
X561	120th/27th/Haas Dr	\$36.76	October 2030
X562	1934 Lincoln Rd	\$106.15	August 2030

Continued on Sheet No. C-45.00

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C11. Customer Attachment Program (Contd)

CAP No.	CAP Name	CAP Charge Per Month	Last Billing Month For Surcharge
X563	LULU/Wells/Ida Center	\$41.15	October 2030
X564	Cherry @ Plum	\$18.51	November 2030
X565	810 N 16th St Main Ext	\$56.92	September 2030
X566	Carter Rd	\$43.17	November 2030
X567	Ruggles Rd	\$20.31	November 2030
X568	2760 Half Moon Lake Rd	\$33.66	November 2030
X569	Woods of Lochaven Condos	\$34.50	December 2030
X570	Mckinley	\$17.22	December 2030
X571	PAW PAW LAKE @ HAGAR SHORE	\$27.88	December 2030
X572	MARRS @ 2170	\$34.09	December 2030
X573	HOLDEN @ LEMON CREEK	\$50.14	February 2031

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Continued from Sheet No. D-1.01

SECTION D
RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

Tax Cut And Jobs Act "Credit A" Portion Credits

This credit allows the Company to refund to customers the impact of the Federal Tax Cuts and Jobs act of 2017, which reflects a reduction in the federal tax rate from 35% to 21%.

Customers shall receive "Credit A" credits until the Company is authorized new base rates in a general rate case proceeding.

<u>Rate Schedule</u>	<u>Credit per Mcf</u>
<u>Residential</u>	<u>(\$0.1242)</u>
<u>Small General Service</u>	<u>(\$0.0738)</u>
<u>Large General Service</u>	<u>(\$0.0408)</u>
<u>Transportation -</u>	
<u>TR 1</u>	<u>(\$0.0274)</u>
<u>TR 2</u>	<u>(\$0.0228)</u>
<u>TR 3</u>	<u>(\$0.0204)</u>
<u>Aggregated - Residential</u>	<u>(\$0.1242)</u>
<u>Aggregated - Small General Service</u>	<u>(\$0.0738)</u>
<u>Aggregated - Large General Service</u>	<u>(\$0.0408)</u>
<u>Choice - Residential</u>	<u>(\$0.1242)</u>
<u>Choice - Small General Service</u>	<u>(\$0.0738)</u>
<u>Choice - Large General Service</u>	<u>(\$0.0408)</u>

Tax Cut And Jobs Act "Credit B" Adjustment

These charges reflect an adjustment to the Tax Cuts and Jobs Act refund you received October 1 to December 31, 2018. Customer's bills shall be adjusted by the "Credit B" charges, per Mcf, effective June 1, 2019 through June 30, 2019 on a service rendered basis.

<u>Rate Schedule</u>	<u>Charge per Mcf</u>
<u>Residential</u>	<u>(\$0.5330)</u>
<u>Small General Service</u>	<u>(\$0.2144)</u>
<u>Large General Service</u>	<u>(\$0.0532)</u>
<u>Transportation -</u>	
<u>TR 1</u>	<u>(\$0.0418)</u>
<u>TR 2</u>	<u>(\$0.0187)</u>
<u>TR 3</u>	<u>(\$0.0177)</u>
<u>Aggregated - Residential</u>	<u>(\$0.5118)</u>
<u>Aggregated - Small General Service</u>	<u>(\$0.3326)</u>
<u>Aggregated - Large General Service</u>	<u>(\$0.1821)</u>
<u>Choice - Residential</u>	<u>(\$0.5694)</u>
<u>Choice - Small General Service</u>	<u>(\$0.2956)</u>

This sheet has been cancelled and held for future use.

Continued on Sheet No. D-1.03

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Continued from Sheet No. D-1.02

**SECTION D
RATE SCHEDULES**

D2. SUPPLEMENTAL CHARGES (contd.)

Tax Cut And Jobs Act "Calculation C" Portion Credits

~~This credit allows the Company to refund to customers the impact of the Federal Tax Cuts and Jobs act of 2017 for excess deferred taxes, bonus depreciation, etc. Customer's bills shall be adjusted by the "Calculation C" credits, per Mcf, on a service rendered basis. Customers shall receive "Calculation C" credits until the Company is authorized new base rates in a general rate case proceeding.~~

<u>Rate Schedule</u>	<u>Effective</u> <u>June 1, 2019</u> <u>to Dec. 31, 2019</u> <u>credit per Mcf</u>	<u>Effective</u> <u>Jan. 1, 2020</u> <u>credit per Mcf</u>
~~Residential~~	~~(\$0.3614)~~	~~(\$0.0579)~~
~~Small General Service~~	~~(\$0.1691)~~	~~(\$0.0288)~~
~~Large General Service~~	~~(\$0.0280)~~	~~(\$0.0056)~~
~~Transportation:~~		
~~—TR-1~~	~~(\$0.0624)~~	~~(\$0.0126)~~
~~—TR-2~~	~~(\$0.0373)~~	~~(\$0.0086)~~
~~—TR-3~~	~~(\$0.0497)~~	~~(\$0.0114)~~
~~—Aggregated—Residential~~	~~(\$0.3439)~~	~~(\$0.0579)~~
~~—Aggregated—Small General Service~~	~~(\$0.1680)~~	~~(\$0.0288)~~
~~—Aggregated—Large General Service~~	~~(\$0.0302)~~	~~(\$0.0056)~~
~~Choice—Residential~~	~~(\$0.3224)~~	~~(\$0.0515)~~
~~Choice—Small General Service~~	~~(\$0.1805)~~	~~(\$0.0302)~~

This sheet has been cancelled and held for future use.

Continued on Sheet No. D-1.04

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Continued from Sheet No. D-1.03

**SECTION D
RATE SCHEDULES**

D2. SUPPLEMENTAL CHARGES (contd.)

**MRP RIDER
MAIN REPLACEMENT PROGRAM RIDER**

1. The MRP Rider is limited to the recovery of the removal and/or replacement of transmission facilities only, specifically those impacted by 49 CFR Part 192 Subpart O or the 2019 Mega Rule.
2. The revenue distribution and the accounting provisions produced from this MRP Rider shall have no precedential value in the company's next rate case.
3. The Company will set up special accounts for the removal and replacement transmission mains affected by 49 CFR Part 192 Subpart O or the 2019 Mega Rule.
4. The Company's proposed recovery is based upon an **annual** revenue requirement calculation by rate schedule with the main allocation factor of average and peak and the corresponding number of customers as approved by the Commission in the Company's most recent rate case.
5. The Company's calculation is based upon the following:
 - a. Original Cost and Accumulated Reserve for Post 12/31/2022
 1. Used and useful after 1/1/2023
 2. Capital expenditures is limited to new plant under this rider
 3. Adjustments for the retirement of existing assets
 - b. Calculation of post in - service carrying charges on net plant additions and related deferred taxes
 1. Calculated from the date that the applicable assets are used and useful, January 1 of the year following installation.
 2. Based on the Company's embedded interest cost and recorded at the gross rate for recovery on deferred taxes that lessens amount for recovery.
 - c. Calculation of deferred taxes on depreciation

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Continued from Sheet No. D-1.04

**SECTION D
RATE SCHEDULES**

D2. SUPPLEMENTAL CHARGES (contd.)

**MRP RIDER
MAIN REPLACEMENT PROGRAM RIDER**

- a. Proper annual depreciation expense
- b. Operation and maintenance expense savings resulting from the MRP
- c. Incremental property taxes associated with net plant additions from the MRP
- d. Expenses associated with the cost of meter relocations, removals and all customer owned service lines

Continued on Sheet No. D-1.06

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Continued from Sheet No. D-1.05

SECTION D RATE SCHEDULES

D2. SUPPLEMENTAL CHARGES (contd.)

MRP RIDER

MAIN REPLACEMENT PROGRAM RIDER

APPLICABILITY

Applicable to all customers receiving service under the Company's sales and transportation rate schedules and Special Contract Customers.

MAIN REPLACEMENT PROGRAM (MRP)

This MRP Rider as approved by the MPSC recovers the cost of the MRP not included in MGUC's base rates. These projects included pipeline replacements and related costs. By having this surcharge in place, MCUC recovers over time the costs associated with these replacement projects, which should reduce the frequency of expensive general rate cases in the future.

All customers receiving service under Rate Schedules Residential, Small General Service, Medium General Service, Large General Service, TR-1, TR-2, TR-3 and Special Contract shall be assessed a monthly charge in addition to the Customer Charge component of their applicable rate which will enable the Company to begin and complete the replacement initiative.

The company can bill this surcharge to all of its customers monthly. The program will be reviewed annually, in order to reflect the impact on the Company's revenue requirements of net plant additions as offset by the operation and maintenance expense reductions during the most recent twelve months ended December 31 of each calendar year.

This Rider surcharge will become effective with the first billing cycle of January 2023, and reflects the allocation of the required revenue increase needed based upon the main allocation factor of average and peak and the number of customers per rate group as defined and approved in the Company's last rate proceeding.

The Rider MRP charge will be implemented on a bill rendered basis beginning in January 2023 and will continue as approved in U-20718 until new rates are established in a future contested case addressing the MRP. Per Customer Meter charges may change annually. The charge for the specific Rate Schedule is:

Continued on Sheet No. D-1.07

Continued from Sheet No. D-1.06

**SECTION D
RATE SCHEDULES**

D2. SUPPLEMENTAL CHARGES (contd.)

MRP RIDER

MAIN REPLACEMENT PROGRAM RIDER

The Rider MRP charge will be implemented on a bill rendered basis beginning in January 2023 and will continue as approved in U-20718 until new rates are established in a future contested case addressing the MRP. Per Customer Meter charges may change annually. The charge for the specific Rate Schedule is:

Customer Class	Per Customer Meter
Residential	\$0.56/month
Small General Service	\$1.30/month
Medium General Service	\$11.61/month
Large General Service	\$21.91/month
Transportation:	
TR-1	\$29.77/month
TR-2	\$189.36/month
TR-3	\$1,161.27/month
Aggregated - Residential	\$1.12/month
Aggregated - Small General Service	\$4.11/month
Aggregated - Medium General Service	\$13.50/month
Aggregated - Large General Service	\$22.88/month
Choice – Residential	\$0.55/month
Choice – Small General Service	\$1.27/month
Choice – Medium General Service	\$8.25/month
Choice – Large General Service	\$15.22/month
Special Contract	\$298.11/month

Rider MRP surcharges will continue until the earlier of either: (i) base rates are established in a future contested case addressing the MRP through self-implementation or Commission Order, or (ii) December 31, 2027.

Continued on Sheet No. D-2.00

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Continued From Sheet No. D-5.00

D4. RESIDENTIAL RATE - (General and Heating) (Contd.)

RATE

Customer Charge: Daily ~~\$0.4274~~ **\$ 0.4849** per customer, or Monthly ~~\$13.00~~ **\$ 14.75** per customer, plus

Distribution Charge
~~\$1.5874~~ **\$1.9363** per Mcf, plus

Gas Supply Acquisition Charge
~~\$0.0790~~ **\$ 0.0631** per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges
This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00, and D-1.01, ~~D-1.02 and D-1.03.~~

Main Replacement Program Rider

This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Seasonal Service Charge
A charge of \$50.00 payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Late Payment Charge and Due Date
A late payment charge of 2%, not compounded, net of sales tax, will be added to any bill which is delinquent. Customers participating in the Winter Protection Plan will not be assessed the late payment charge. The due date shall be 21 days following the date of mailing.

Minimum Payment Option (MPO):
This option is available for Residential customers who are faced with disconnection of utility service because of past-due utility bills. Customers will be given an option to pay a percentage of the total bill (arrearage and current bill) to avoid disconnection of service. The percentage will begin at 30%. It may increase or decrease for subsequent billing cycles by up to 10% for each succeeding month, but at no time will it exceed 60% of the balance as the minimum amount. If the customer pays the minimum payment option, and the following month the arrears still fall within the disconnection parameters, the customer will be given this minimum payment option again.

Other payment options include full payment, **the Winter Protection Program** and deferred payment arrangements.

GAS ALLOCATION PROCEDURE

This rate schedule is subject to the provisions of Rule C2.7.

Continued on Sheet No. D-7.00

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Continued from Sheet No. D-8.00

D5. SMALL GENERAL SERVICE RATE - (General and Heating) (Contd)

GAS ALLOCATION PROCEDURE

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TAXES

- (1) In municipalities which levy special taxes, license fees, or street rentals against the Company, and which levy has been successfully maintained, the standard of rates shall be increased within the limits of such municipalities so as to offset such special charges and thereby prevent the customers in other localities from being compelled to share any portion of such local increase.
- (2) Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's production, transmission or sale of gas.

RULES AND REGULATIONS

Services under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

Continued on Sheet No. D-10.00

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Continued from Sheet No. D-9.00

D5. SMALL GENERAL SERVICE RATE - (General and Heating) (Contd)

ANNUAL RATE AUDIT

All non-residential general service accounts will be reviewed each year to ensure their annual usage is within the usage requirements of their rate class plus or minus 10% from the breakpoint quantity. Annual usage shall be determined on the basis of: 1) the twelve (12) month period typically ending in December of each year; 2) such other twelve (12) month period as may be agreed upon; or 3) a partial period of less than twelve (12) months as determined by the customer's initial date of service and the company's next regularly scheduled annual rate audit period.

Any customer whose annual usage falls outside of the usage requirements of their current rate class plus or minus 10% from the breakpoint quantity will be transferred to the appropriate rate schedule for which the customer is eligible.

Reclassification based on annual rate audits will be made prospectively.

Partial period rate audits will be conducted in those instances in which the company's review of the customer's monthly usage suggests that the customer may have been incorrectly classified regarding the appropriate rate class at the time of service initiation. Reclassification based on partial period rate audits will be at the sole discretion of the company, and any contract change will be made prospectively.

Continued on Sheet No. D-11.00

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Continued from Sheet No. D-10.00

D6. ~~SMALL-MEDIUM~~ GENERAL SERVICE RATE - (General and Heating)

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company, service is available under this rate schedule to any non-residential customer for any purpose with annual usage between 3,300 – 8,300 Mcf. The customers of this class will be subject to an Annual Rate Audit as described below.

RATE

Customer Charge:

\$ 4.4384 Daily per customer, or \$ 135.00 Monthly per customer, plus

Distribution Charge
\$ 1.7741 per Mcf, plus

Gas Supply Acquisition Charge
\$ 0.0631 per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges:
This rate is subject to the Supplemental Charges set forth on Sheet N No. S. D-1.00 and D-1.01.

Main Replacement Program Rider

This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Seasonal Service Charge

A charge of \$50.00, payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Delayed Payment Charge and Due Date

A delayed payment charge of 2% shall be applied to the unpaid balance outstanding not compounded, net of sales tax, of any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

Continued on Sheet No. D-12.00

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Continued From Sheet No. D-11.00

D6. SMALL MEDIUM GENERAL SERVICE RATE - (General and Heating) (Contd)

GAS ALLOCATION PROCEDURE

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TAXES

- (1) In municipalities which levy special taxes, license fees, or street rentals against the Company, and which levy has been successfully maintained, the standard of rates shall be increased within the limits of such municipalities so as to offset such special charges and thereby prevent the customers in other localities from being compelled to share any portion of such local increase.
- (2) Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's production, transmission or sale of gas.

RULES AND REGULATIONS

Services under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

Continued on Sheet No. D-13.00

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Continued from Sheet No. D-12.00

D67. LARGE MEDIUM GENERAL SERVICE RATE - (General and Heating) (Contd)

ANNUAL RATE AUDIT

All non-residential general service accounts will be reviewed each year to ensure their annual usage is within the usage requirements of their rate class plus or minus 10% from the breakpoint quantity. Annual usage shall be determined on the basis of: 1) the twelve (12) month period typically ending in December of each year; 2) such other twelve (12) month period as may be agreed upon; or 3) a partial period of less than twelve (12) months as determined by the customer's initial date of service and the company's next regularly scheduled annual rate audit period.

Any customer whose annual usage falls outside of the usage requirements of their current rate class plus or minus 10% from the breakpoint quantity will be transferred to the appropriate rate schedule for which the customer is eligible.

Reclassification based on annual rate audits will be made prospectively.

Partial period rate audits will be conducted in those instances in which the company's review of the customer's monthly usage suggests that the customer may have been incorrectly classified regarding the appropriate rate class at the time of service initiation. Reclassification based on partial period rate audits will be at the sole discretion of the company, and any contract change will be made prospectively.

Continued on Sheet No. D-14.00

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Continued from Sheet No. D-13.00

D7. LARGE GENERAL SERVICE RATE - (General and Heating)

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company, service is available under this rate schedule to any non-residential customer for any purpose with annual usage above 8,300 Mcf. The customers of this class will be subject to an Annual Rate Audit as described below.

RATE

Customer Charge:

	<u>Daily</u>	<u>Monthly</u>
	\$13.9726 per customer, or	\$ 425.00 per customer, plus

Distribution Charge

~~\$1.0322~~ \$ 1.3577 per Mcf, plus

Gas Supply Acquisition Charge

~~0.0790~~ \$ 0.0631 per Mcf (This charge is not applicable to Gas Choice customers or Aggregated Transportation accounts.)

Gas Cost Recovery Charge

The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges:

This rate is subject to the Supplemental Charges set forth on Sheet No. D-1.00 and D-1.01.

Main Replacement Program Rider

This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

Seasonal Service Charge

A charge of \$50.00, payable in either a flat amount or three equal installments, will be made to partially cover the cost of restoring service when it has been temporarily discontinued at the customer's request.

Delayed Payment Charge and Due Date

A delayed payment charge of 2% shall be applied to the unpaid balance outstanding not compounded, net of sales tax, of any bill which is not paid on or before the due date shown thereon. The due date shall be 21 days following the date of mailing.

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Continued from Sheet No. D-14.00

D7. LARGE GENERAL SERVICE RATE - (General and Heating) (Contd)

GAS ALLOCATION PROCEDURE

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TAXES

- (1) In municipalities which levy special taxes, license fees, or street rentals against the Company, and which levy has been successfully maintained, the standard of rates shall be increased within the limits of such municipalities so as to offset such special charges and thereby prevent the customers in other localities from being compelled to share any portion of such local increase.
- (2) Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's production, transmission or sale of gas.

RULES AND REGULATIONS

Services under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

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D7. LARGE GENERAL SERVICE RATE - (General and Heating)

ANNUAL RATE AUDIT

All non-residential general service accounts will be reviewed each year to ensure their annual usage is within the usage requirements of their rate class plus or minus 10% from the breakpoint quantity. Annual usage shall be determined on the basis of: 1) the twelve (12) month period typically ending in December of each year; 2) such other twelve (12) month period as may be agreed upon; or 3) a partial period of less than twelve (12) months as determined by the customer's initial date of service and the company's next regularly scheduled annual rate audit period.

Any customer whose annual usage falls outside of the usage requirements of their current rate class plus or minus 10% from the breakpoint quantity will be transferred to the appropriate rate schedule for which the customer is eligible.

Reclassification based on annual rate audits will be made prospectively.

Partial period rate audits will be conducted in those instances in which the company's review of the customer's monthly usage suggests that the customer may have been incorrectly classified regarding the appropriate rate class at the time of service initiation. Reclassification based on partial period rate audits will be at the sole discretion of the company, and any contract change will be made prospectively.

Continued on Sheet No. D-17.00

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D8. GAS LIGHTING RATE

AVAILABILITY

Subject to limitations and restrictions contained in orders of the Michigan Public Service Commission in effect from time to time and in the Rules and Regulations of the Company.

<u>Rate Schedule</u>	<u>Distribution Charge</u>
~~Residential -~~	~~\$ 1.5871 per Mcf~~
Commercial -	~~\$1.5870~~ <u>\$2.0853</u> per Mcf

Street Lights - (In accordance with the terms of the service agreement)

Gas Supply Acquisition Charge
~~\$0.0790~~ \$ 0.0631 per Mcf

Gas Cost Recovery Charge
The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges
This rate is subject to the Supplemental Charges set forth on Sheet No. D-1.00 and D-1.01.

Main Replacement Program Rider
This rate is subject to the Main Replacement Program Rider charges set forth on Sheet Nos. D-1.04, D-1.05, D-1.06 and D-1.07.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company plus the following condition:

No additional gas burning devices may be attached to the service connection for light(s) served under this rate.

SPECIAL TAXES

- (1) In municipalities which levy special taxes, license fees, or street rentals against the Company, and which levy has been successfully maintained, the standard of rates shall be increased within the limits of such municipalities so as to offset such special charges and thereby prevent the customers in other localities from being compelled to share any portion of such local increase.
- (2) Bills shall be increased to offset any new or increased special tax or excise imposed by any governmental authority upon the Company's production, transmission or sale of gas.

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D9. RESIDENTIAL SERVICE – GAS DEMAND RESPONSE PROGRAM

AVAILABILITY

This schedule is available on an optional basis to residential customers. The Company has the right to limit this tariff to 50 customers.

DEFINITIONS

Gas Demand Response events will be communicated by the Company by e-mail, SMS/text messaging or phone call.

Gas Demand Response rewards will be issued at random, at the sole discretion of the Company, in the form of a one in ten chance to win a \$50 Gift Card. This is to occur within 30 days of the start of the heating season (Nov 1). An additional one in ten chance to win A \$25 Gift Card will occur within 30 days at the end of the heating season (Mar 31).

RATE

Charges as set forth on Sheet No. D-6.00.

Customer Charge
Distribution Charge
Gas Supply Acquisition Charge
Seasonal Service Charge
Late Payment Charge

Gas Cost Recovery Charge

The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges

This rate is subject to the Supplemental Charges set forth on Sheet No. D-1.00 and D-1.01.

Special Taxes

This rate is subject to the Special Taxes set forth on Sheet No. D-7.00.

Main Replacement Program Rider

This rate is subject to the Main replacement Program Rider charges set forth on Sheet No. D-1.07.

Gas Allocation Procedure

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TERMS AND PROVISIONS

This Rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated unless otherwise approved by the Company.

Availability is subject to the ability of the Company to obtain and install the required metering.

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D9. RESIDENTIAL SERVICE – GAS DEMAND RESPONSE PROGRAM (Contd.)

SPECIAL TERMS AND PROVISIONS (Contd.)

Each participating customer who remains eligible to participate in the subsequent term shall be automatically re-enrolled every 12 months with at least (30) day notice. The Customer shall have the right to rescind the re-enrollment until and including 30 days from the program enrollment anniversary date. Any request to be removed from the program shall take effect at the start of the next billing cycle.

The Company shall have the sole discretion to initiate critical events up to 72 hours during the calendar year. Customers shall be provided with a minimum of one hour notice prior to initiation of a critical event. The minimum length of an interruption shall be 2 hours and the maximum length of an interruption shall be 8 hours.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

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D10. SMALL GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM

AVAILABILITY

This schedule is available on an optional basis to small general service customers. The Company has the right to limit this tariff to 15 customers.

DEFINITIONS

Gas Demand Response events will be communicated by the Company by e-mail, SMS/text messaging or phone call.

Gas Demand Response rewards will be issued at random, at the sole discretion of the Company, in the form of a one in ten chance to win a \$50 Gift Card. This is to occur within 30 days of the start of the heating season (Nov 1). An additional one in ten chance to win A \$25 Gift Card will occur within 30 days at the end of the heating season (Mar 31).

RATE

Charges as set forth on Sheet No. D-8.00.

Customer Charge
Distribution Charge
Gas Supply Acquisition Charge
Seasonal Service Charge
Delayed Payment Charge and Due Date

Gas Cost Recovery Charge

The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges

This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D1.01.

Main Replacement Program Rider

This rate is subject to the Main replacement Program Rider charges set forth on Sheet No. D-1.07.

Special Taxes

This rate is subject to the Special Taxes set forth on Sheet No. D-9.00.

Gas Allocation Procedure

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TERMS AND PROVISIONS

This Rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated unless otherwise approved by the Company.

Availability is subject to the ability of the Company to obtain and install the required metering.

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D10. SMALL GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM (Contd.)

SPECIAL TERMS AND PROVISIONS (Contd.)

Each participating customer who remains eligible to participate in the subsequent term shall be automatically re-enrolled every 12 months with at least (30) day notice. The Customer shall have the right to rescind the re-enrollment until and including 30 days from the program enrollment anniversary date. Any request to be removed from the program shall take effect at the start of the next billing cycle.

The Company shall have the sole discretion to initiate critical events up to 72 hours during the calendar year. Customers shall be provided with a minimum of one hour notice prior to initiation of a critical event. The minimum length of an interruption shall be 2 hours and the maximum length of an interruption shall be 8 hours.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

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D11. MEDIUM GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM

AVAILABILITY

This schedule is available on an optional basis to small general service customers. The Company has the right to limit this tariff to 10 customers.

DEFINITIONS

Gas Demand Response events will be communicated by the Company by e-mail, SMS/text messaging or phone call.

Gas Demand Response rewards will be issued at random, at the sole discretion of the Company, in the form of a one in ten chance to win a \$50 Gift Card. This is to occur within 30 days of the start of the heating season (Nov 1). An additional one in ten chance to win A \$25 Gift Card will occur within 30 days at the end of the heating season (Mar 31).

RATE

Charges as set forth on Sheet No. D-11.00.

Customer Charge
Distribution Charge
Gas Supply Acquisition Charge
Seasonal Service Charge
Delayed Payment Charge and Due Date

Gas Cost Recovery Charge

The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges

This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D1.01.

Main Replacement Program Rider

This rate is subject to the Main replacement Program Rider charges set forth on Sheet No. D-1.07.

Special Taxes

This rate is subject to the Special Taxes set forth on Sheet No. D-12.00.

Gas Allocation Procedure

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TERMS AND PROVISIONS

This Rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated unless otherwise approved by the Company.

Availability is subject to the ability of the Company to obtain and install the required metering.

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D11. MEDIUM GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM (Contd.)

SPECIAL TERMS AND PROVISIONS (Contd.)

Each participating customer who remains eligible to participate in the subsequent term shall be automatically re-enrolled every 12 months with at least (30) day notice. The Customer shall have the right to rescind the re-enrollment until and including 30 days from the program enrollment anniversary date. Any request to be removed from the program shall take effect at the start of the next billing cycle.

The Company shall have the sole discretion to initiate critical events up to 72 hours during the calendar year. Customers shall be provided with a minimum of one hour notice prior to initiation of a critical event. The minimum length of an interruption shall be 2 hours and the maximum length of an interruption shall be 8 hours.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

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D12. LARGE GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM

AVAILABILITY

This schedule is available on an optional basis to large general service customers. The Company has the right to limit this tariff to 5 customers.

DEFINITIONS

Gas Demand Response events will be communicated by the Company by e-mail, SMS/text messaging or phone call.

Gas Demand Response rewards will be issued at random, at the sole discretion of the Company, in the form of a one in ten chance to win a \$50 Gift Card. This is to occur within 30 days of the start of the heating season (Nov 1). An additional one in ten chance to win A \$25 Gift Card will occur within 30 days at the end of the heating season (Mar 31).

RATE

Charges as set forth on Sheet No. D-14.00.

Customer Charge
Distribution Charge
Gas Supply Acquisition Charge
Seasonal Service Charge
Delayed Payment Charge and Due Date

Gas Cost Recovery Charge

The monthly gas cost recovery charge as set forth on Sheet No. D-2.00.

Supplemental Charges

This rate is subject to the Supplemental Charges set forth on Sheet Nos. D-1.00 and D1.01.

Main Replacement Program Rider

This rate is subject to the Main replacement Program Rider charges set forth on Sheet No. D-1.07.

Special Taxes

This rate is subject to the Special Taxes set forth on Sheet No. D-15.00.

Gas Allocation Procedure

This rate schedule is subject to the provisions of Rule C2.7.

SPECIAL TERMS AND PROVISIONS

This Rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated unless otherwise approved by the Company.

Availability is subject to the ability of the Company to obtain and install the required metering.

Continued on Sheet No. D-25.00

Continued from Sheet No. D-24.00

D12. LARGE GENERAL SERVICE RATE – GAS DEMAND RESPONSE PROGRAM (Contd.)

SPECIAL TERMS AND PROVISIONS (Contd.)

Each participating customer who remains eligible to participate in the subsequent term shall be automatically re-enrolled every 12 months with at least (30) day notice. The Customer shall have the right to rescind the re-enrollment until and including 30 days from the program enrollment anniversary date. Any request to be removed from the program shall take effect at the start of the next billing cycle.

The Company shall have the sole discretion to initiate critical events up to 72 hours during the calendar year. Customers shall be provided with a minimum of one hour notice prior to initiation of a critical event. The minimum length of an interruption shall be 2 hours and the maximum length of an interruption shall be 8 hours.

RULES AND REGULATIONS

Service under this rate schedule shall be subject to the Standard Rules and Regulations of the Company.

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E1.3 Possession of gas. (Contd)

(b) Indemnification of the Company.

In the absence of negligence, recklessness or willful misconduct on the part of the Company or the Company's directors, officers, employees or agents, the customer waives any and all claims against the Company, its officers, its employees or its agents, arising out of or in any way connected with: (a) the quality, use, or condition of the gas after redelivery from the Company's line for the account of the customer; (b) any losses or shrinkage of gas during or resulting from transportation; and (c) all other claims and demands arising out of the performance of the duties of the Company, its directors, its officers, its employees, or its agents.

E2. RECORDS, ACCOUNTING AND CONTROL

(a) Mailing of notices, bills, and payments.

All notices, bills and payments required or permitted to be given in connection with transportation service shall be sent to the address specified in the customer's contract unless otherwise indicated therein; shall be in writing and shall be valid and sufficient if delivered in person or by first class mail, Western Union, or telex.

(b) Nominations, accounting, and controls.

Requirements. Customers are required to have a nomination on file for each day of the month. (A single nomination shall be assumed to apply for each subsequent day of the month, unless otherwise indicated.) Customers requesting volumes to flow on the first day of any month must contact Company's Gas Control Department via Company's Internet-enabled electronic bulletin board (**EBB**), ~~known as Transportation Web Access ("TWA")~~ (<https://accel.michigangasutilities.com/ICSLogin/?https://accel.michigangasutilities.com/energyinformation/> ~~"D5"~~) and inform them of the volumes to be transported by receipt point(s) and delivery point(s). **All nominations to the company must be in accordance with the deadlines of the North American Energy Standards Board (NAESB) Standard 1.3.2. First of the month nominations and subsequent nomination changes via the Internet are due by 11:30 a.m. Central Time one day before the gas flows. Intra-day nomination changes for the 2nd through the end of a month will be accepted until 5:00 p.m. Central Time.** A confirmed pipeline nomination will also be accepted on a best effort basis on the day of gas flow. The Company shall have the right, in its sole discretion, to reject or change any nomination that does not match the corresponding interstate pipeline nomination, or conflicts with the Operational Flow Orders (OFO) of the Company pursuant to Rule C3.2(c) on Sheet Nos. C-10.00 through C-14.00. **In the event that NAESB Standards change, nominations to the company may change as necessary.**

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E2. Records, accounting, and control. (Contd)

On **EBBTWA**, the customer or designated representative is to input the delivery point on Michigan Gas Utilities system, the pipeline (shipper's) name and contract number, and the delivered volume of gas it desires the Company to receive on the customer's behalf during the month. The Company will also make Critical Day and other important operational notices that may affect nominations available via **EBBTWA**. If circumstances arise whereby **EBBTWA** is not available, the Company will use a paper-based nominations process until **EBBTWA** is back on-line. The customer and the Company shall inform each other of any changes in anticipated deliveries immediately. Changes in monthly and daily nominations may be necessary to accommodate certain operating conditions such as the implementation of an Operational Flow Order (OFO) by the Company pursuant to Rule C3.2(c) on Sheet Nos. C-10.00 through C-14.00 and for monthly load balancing purposes as described on Sheet Nos. E-14.00 through E-17.00.

E3. GAS QUALITY

- (a) The quality of gas delivered to the Company shall meet the following requirements:
 - (i) Gas shall not contain more than three percent oxygen by volume;
 - (ii) Gas shall be commercially free from objectionable odors, solid or liquid matter, dust, gum or gum-forming constituents that might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters, or other appliances through which it flows;
 - (iii) Gas shall not contain more than 0.3 grain of hydrogen sulphide per 100 cubic feet;
 - (iv) Gas shall not contain more than twenty grains of total sulfur (including hydrogen sulfide and mercaptan sulfur) per 100 cubic feet;
 - (v) Gas shall not at any time have a carbon dioxide content in excess of two percent by volume;
 - (vi) Gas shall not contain an amount of moisture which at any time exceeds seven pounds per million cubic feet; and

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E5. TRANSPORTATION SERVICE AND RATES

E5.1 AVAILABILITY.

This service is available to any customer that could otherwise purchase gas under any of the Company's existing sales tariffs.

The customer must contract for delivery to a specific metering point(s) where the gas will be consumed. Gas transported under this rate may not be resold.

The Customer has agreed to provide a separate telephone line and such other facilities as may be required for the specialized metering equipment needed to be installed by the Company. The Customer has also agreed to provide 24 hour per day access to the specialized metering equipment located on the Customer's premises.

Upon request, the Company will make available to the Customer the daily volumetric data collected from the specialized metering equipment ~~within two hours following the end of the Gas Day.~~ However, such requests do not relieve the customer of the responsibility to balance its gas usage compared to deliveries of supplies into the Company's distribution system when an OFO has been instituted. Should a customer seek real time volumetric flow data, the Company will work with that customer, at the customer's expense for the equipment, to install the appropriate equipment to duplicate invoice quality data.

The Company does not have the obligation to provide GCR sales service until 30 days after notification of the customer's intention to become a sales customer.

The Company makes no guarantee against, and assumes no liability for, interruptions caused by third parties, including suppliers, marketers, producers, and pipelines.

E5.2 NATURE OF SERVICE.

The Company will accept on a firm basis, gas delivered to it on behalf of a transportation customer. The Company will redeliver an amount of gas to the customer containing the equivalent British thermal unit (BTU) content of the gas delivered to the Company on behalf of the customer.

Bills will be rendered on a monthly basis.

Service will be rendered under the terms and conditions contained in this rate schedule and consistent with the Company's Rule E1 - GAS TRANSPORTATION SERVICE RULES.

E5.3 AGGREGATION OF ACCOUNTS OPTION.

A customer receiving gas service at multiple facilities under common ownership may elect to aggregate the quantities of gas supplied to such facilities if the following conditions are met:

- (a) The customer must designate one of the facilities as the master account. The master account must be a Transportation Service account (TR-1, TR-2 or TR-3).

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E5. TRANSPORTATION SERVICE AND RATES (Contd)

E5.3 AGGREGATION OF ACCOUNTS OPTION

- (b) Only the subsidiary accounts will be eligible for aggregation with the master account. To qualify as a subsidiary account a facility must be served under any of the Sales Service Rates or Transportation Service Rates. The customer, or the customer's agent, must specify which of the other facilities will be designated as a subsidiary account. The customer may designate some or all of its other facilities as subsidiary accounts.
- (c) The facility designated as the master account shall be subject to and billed under the provisions of its transportation tariff. Facilities designated as subsidiary accounts shall be subject to all the terms and conditions of the master account tariff, except that each subsidiary account will pay the customer charge, distribution charge and all applicable Supplemental charges as set forth on Sheet Nos. D-1.00, **and D-1.01, ~~D-1.02 and D-1.03~~** in effect for its designated sales or transportation rate, rather than the customer charge and transportation charge in effect for the master account.
- (d) Each subsidiary account will be required to have remote metering installed and will be subject to the Daily Balancing provisions contained in Section 5.8 below. Each subsidiary account will be subject to a monthly telemetering charge of \$21.50, which is in addition to the charges specified in Section E5.3 (c) above.

E5.4 RATES AND CHARGES

Monthly Charges:	Transportation Service Rate		
	TR-1	TR-2	TR-3
Customer Charge -			
Each Meter	\$ 1,200.00 / meter	\$ 2,600.00 / meter	\$ 3,300.00 / meter
Each Subsidiary Account	\$ 21.50 / meter	\$ 21.50 / meter	\$ 21.50 / meter
Transportation Rates:			
Peak (November to March)	\$ 0.8244 per Mcf	\$ 0.5324 per Mcf	\$ 0.5177 per Mcf
Off-Peak (April to October)	\$ 0.6744 per Mcf	\$ 0.3824 per Mcf	\$ 0.3677 per Mcf

Service Category

- TR-1 Usage between 0 and 57,500 Mcf annually
TR-2 Usage between 57,500 and 571,400 Mcf annually
TR-3 Usage greater than 571,400 Mcf annually

Optional Discount Rates - The Company, at its discretion, may negotiate lower rates for individual customers, down to a minimum of \$0.20 per Mcf.

DAILY BALANCING SERVICE	Effective
% Difference From Nomination	Rate Per Mcf
>0.0% up to 8.0%	\$0.2291
>8.0%	\$0.4041

Applicable Daily Balancing Charges for Undertake Imbalances during High Flow Constraint Periods and Overtake Imbalances during Low Flow Constraint Periods

% Difference From Nomination	Effective
	Rate Per Mcf
>0.0% up to 10.0%	\$0.0000
>10.0%	\$0.6300

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E5. TRANSPORTATION SERVICE AND RATES (Contd)

The Company, at its option, may require the installation of a heating value measurement device and the payment by the customer of a \$250.00 monthly heating value measurement charge under the following conditions:

- (a) If the customer refuses to include in its gas transportation service contract a provision that holds the Company harmless for any damages resulting from measuring errors; or
- (b) If the customer demands that heating value measurement equipment be installed.

Main Replacement Program Rider

This rate is subject to the Main replacement Program Rider charges set forth on Sheet No. D-1.07.

E5.5 GAS COST RECOVERY

Gas transported under this rate is not subject to adjustments for fluctuations in the cost of purchased gas as stated in Rule C9 of the Company's Rules, Regulations, and Rate Schedules, M.P.S.C. No. 2.

E5.6 SUPPLEMENTAL CHARGES

This rate may be subject to the Supplemental Charges set forth on Sheet No. D-1.00, **and D-1.01, D-1.02 and D-1.03.**

E5.7 GAS-IN-KIND

The Company shall retain 0.31% of all gas received at the delivery point(s) to compensate it for the company-use and lost-and-unaccounted-for gas on the Company's system. This volume shall not be included in the quantity available for redelivery to the customer.

E5.8 DAILY BALANCING SERVICE

ANNUAL CONTRACT QUANTITY (ACQ) is defined as the quantity of gas, as specified in the transportation contract between the customer and the Company, that is based on the customer's maximum historical 12-month usage (determined from the customer's 36-month base period) plus adjustments for known or expected changes. The ACQ will be utilized in establishing the customer's Maximum Daily Quantity (MDQ), unless an alternative measure is agreed upon.

ADJUSTED SCHEDULED DELIVERED QUANTITY is defined as the quantity of gas to be delivered to the Company's system on behalf of the customer as reported by the interstate pipeline, adjusted for the difference in MGU's pressure base (14.73/14.65 psia, i.e. 1.0055).

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E5. TRANSPORTATION SERVICE AND RATES (Contd)

E5.8 DAILY BALANCING SERVICE (Contd.)

POOLING OPTION:

Any customer or customer's agent that causes multiple deliveries at any receipt point to Michigan Gas Utilities may, for the purposes of daily balancing, pool those deliveries together under the following option:

Pooling by Pipeline

Deliveries under this option may be pooled, provided that each delivery into the pool is to a customer or customers that utilize(s) a common Up-stream transportation provider.

The customer, or an agent acting on the customer's behalf, may select this Pooling option for a month provided that it notifies the Company in writing at least thirty (30) days prior to the due date for nominations for the month of effective service. Such notifications must include a listing of the customers to be included in the pool. A customer decision to select this pooling option, as well as the allocation method, is binding for that entire month. This Pooling option does not excuse the customer from its obligations to make timely nominations.

A current transportation customer, or an agent acting on the customer's behalf, must provide supporting paperwork to enroll the customer thirty (30) days prior to the start with a new supplier. Suppliers no longer servicing a customer must provide supporting paperwork thirty (30) days prior to last service date. Customer shall be responsible for notifying previous supplier of discontinued service. The Company shall incur no liability for relying on information from a customer or a Supplier which the company believes to be genuine.

A new transportation customer, or agent acting on the customer's behalf, must notify the Company in writing up to sixty (60) days prior to the due date for nomination for the month of effective transportation service to allow sufficient time for installation of new metering equipment as needed.

Deliveries are pooled together by adding the positive and negative imbalances for each customer in the pool. A fee of \$25.00 per month shall be imposed on each imbalance paper pool, with the fee billed to the marketer, broker, or aggregator that is designated as the pool's representative.

The Pool Administrator will be responsible for determining how any charges or credits will be divided among Third Party Pool members. As soon as the data becomes available to the Company, the Pool Administrator will be given individual Third Party Pool member usage information by the Company for the previous month. The Company will then bill the Pool Administrator. If the Pool Administrator defaults on the payment of any charges, the Company reserves the right to allocate charges to each Pool member and/or the Pool Administrator using its sole discretion.

Continued on Sheet No. E-17.00

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Continued From Sheet No. F-1.00

F1. GENERAL PROVISIONS (Contd.)

- (5) **Supplier Pricing:** A Supplier shall be limited to no more than a total of ten (10) Pricing Categories, until such time as the Company's billing system can accommodate additional categories. A Supplier will not be permitted to add more than two (2) Pricing Categories per month, unless prior approval is obtained from the Company. Each month, all customers within a Pricing Category shall be billed the same price, as designated by the Supplier. A Supplier shall pay a monthly Administrative Fee of \$100.00 per Supplier-designated Pricing Category. A "Pricing Category" shall be defined as a pricing pool that assesses the same rate for each of the Company's five operating districts. The Company reserves the right to require additional pools to meet operational requirements.

- (6) **Daily Delivery Obligations:** The Company will provide each Supplier with a monthly daily schedule of quantities for delivery of gas into the Company system on behalf of the Supplier's customers for each Pricing Category and delivery pools behind each of the Company's five operating districts. ~~Seven (7) business days prior to the end of the preceding month, the Company will issue a Daily Delivery Obligation (DDO).~~ The DDO will establish the anticipated daily quantity of gas to be delivered to the Company at the Point(s) of Receipt designated by the Company. ~~The DDO will generally be based upon the pooled customers' historical use for the prior year, adjusted for the prior year's weather. The DDO shall be calculated using the Company's estimation procedure. This procedure incorporates the unique heating and non-heating factors for each customer in the Pool and Heating Degree Day's.~~ This schedule may be updated by the Company on a monthly daily basis. The Company reserves the right to take into consideration the Supplier's cumulative imbalance in determining each month's DDO. ~~The DDO is subject to intra-month changes as operational conditions dictate. If the Company requires an increase or decrease in flow requirements within any month, the Company shall issue a DDO Change Notice to the Supplier as soon as possible but no later than twenty-four (24) hours prior to the start of the Gas Day. During the calendar month, on the business day prior to the day of flow, the Company shall notify each Supplier by 8:30 A.M. Central Time of the DDO for the next five days of flow. If the Company has, for any reason, not posted on its electronic bulletin board (EBB) or otherwise notified the Suppliers of the DDO on or before 8:45 A.M. Central Time on any business day, the Supplier shall deliver a quantity within the previously forecasted DDO.~~ The Company shall issue such notices in a non-discriminatory manner. Scheduled daily volumes for GCC customers for electric peakers, greenhouses, grain dryers, asphalt plants and large loads without consistent or historical load information may be determined by the Company on a different basis than set forth above.

A Supplier that fails to deliver the required DDO quantity on any day, shall pay a per MMBtu "Failure Fee" for the difference between the required DDO and the actual amount delivered in the amount of \$6.00 per MMBtu (\$10.00 per MMBtu during periods of Company-declared OFO conditions in accordance with Rule C3.2, Curtailment of Gas Service) plus the higher of (a) the cost of gas billed to sales customers pursuant to the Company's Rule C9 or (b) the current highest spot price paid for gas delivered to ANR Pipeline Company, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, the MichCon index or at Chicago city gate for the corresponding date as published in Gas Daily, plus associated firm pipeline delivery costs. In addition, the Company may assess up-stream penalties to the Supplier to the extent that the Company has identified the Supplier as the cause of the penalty. (Failure Fees collected by the Company shall be reflected as a reduction to the GCR Cost of Gas Sold and identified separately on annual reconciliation reports under Rule C9.)

A Supplier who fails to deliver gas on successive days such that its Failure Fee liability exceeds its cash deposit, letter of credit or surety bond, shall be subject to having its Authorized Supplier status revoked. Subject to Rule C2, Controlled Service, the Supplier's customers shall become sales rate customers of the Company.

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Continued From Sheet No. F-2.00

F1. GENERAL PROVISIONS (Contd.)

- (7) **Proof Of Capacity:** The Supplier shall be responsible for obtaining sufficient pipeline capacity to meet its delivery obligations.
- (8) Gas delivered into the Company's system shall comply with Rule B1, Technical Standards for Gas Service, Part 8 Gas Quality.
- (9) **Nominations:** Each Supplier shall notify the Company's Gas Transportation Services Department of the daily quantity of gas (in MMBtu) that the Supplier is nominating for delivery on behalf of each Supplier-designated monthly Pricing Category and each associated geographic delivery pool. Such nominations shall be submitted ~~by 11:30 AM Central time prior to the effective day of the proposed delivery~~ in accordance with the deadlines of the North American Energy Standards Board (NAESB) Standard 1.3.2.
- (10) **Customer Billing:** All customer billing and remittance processing functions for services provided under Rate CC will be performed by the Company. The Supplier will be charged a monthly fee equal to the First Class postage rate for each customer account. The Company will be responsible for credit and collection activities for the amounts billed directly to the customer by the Company. The Supplier must, at least three business days prior to the start of each billing month, furnish to the Company, in a format acceptable to the Company, the price per Mcf or Ccf to be billed to each Supplier-designated Pricing Category on its behalf or the most recently supplied price will be used.
- (11) **Buy/Sell:** The Company shall remit to the Supplier, approximately 21 business days from the end of each calendar month, an amount for the cost of gas equal to the MMBtu quantities **for each Supplier's DDO by pricing pool**, multiplied by the price per Mcf converted to MMBtu, billed to the Supplier's customers that month. The amount to be remitted shall be reduced for any applicable Administrative Fees, Billing Fees, and Failure Fees, amounts owed under the annual price reconciliation per Paragraph (12) below and/or other amounts owed to the Company pursuant to the Company's tariff.
- (12) **Annual Reconciliation:** Within 60 working days after the end of the **March** billing cycle, or upon revocation of a Supplier's Authorized Supplier status, the Company will determine if a reconciling adjustment is necessary, both price and volume will be reviewed.

The Company will compare:

- (i) the weighted average price per MCF billed the customer on behalf of the Supplier with the Company's actual weighted average cost of gas (WACOG), and
- (ii) the volumes delivered by the Supplier, converted to Mcf, with the billed customer consumption over the program year.

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Continued From Sheet No. F-5.00

F2. CUSTOMER PROTECTIONS

DEFINITIONS:

Alternative Gas Supplier (AGS) or Supplier means a marketer, broker, producer, or other entity that has received a license from the Commission and executed an Authorized Gas Supplier Agreement with the Company to deliver gas supplies to customers under Rate CC.

Customer:

- Residential means a purchaser (account holder) of natural gas that is supplied or distributed by a utility for residential purposes.
- Small Commercial means a non-residential customer (business name) with aggregate usage of ~~500~~ 3,300 Mcf of natural gas or less per year.
- Medium Commercial means a non-residential customer (business name) with aggregate usage between 3,300 Mcf and 8,300 of natural gas per year that is supplied or distributed by a utility for non-residential purposes.
- Large Commercial means a non-residential customer (business name) with aggregate usage above ~~300~~ 8,300 Mcf of natural gas per year that is supplied or distributed by a utility for non-residential purposes.

Legally Authorized Person means the person that has legal documentation or legal authority to enroll a residential or commercial customer into a binding contract. A legally authorized person includes, but is not limited to, an individual with power of attorney or a corporate agent authorized to enter into contracts on a corporation's behalf.

Program means the Gas Customer Choice Program approved by the Commission.

The terms "signature" or "signed" includes electronic signatures as defined in the Michigan Uniform Electronic Transactions Act.

These provisions shall be monitored and enforced solely by the Commission or its Staff.

- (1) A Supplier must provide residential and small commercial customers with a 30-day unconditional right to cancel the contract without termination fees following the date the customer signs the contract. The first day of the 30-day period is the day after the contract is entered into by the customer. The exercise of this unconditional right by the customer may occur through a verbal or written communication with the Supplier. The Supplier shall promptly submit a de-enrollment file to the Company within three (3) business days after receiving notice that a customer has cancelled the contract in order to return to the Company's sales rate. The Supplier shall not submit a de-enrollment file to the Company if the customer is transferring to another AGS. A customer who cancels within the specified period will be treated as not having exercised their customer choice option with respect to the enrollment which is cancelled. The Company is not required to de-enroll a customer until after it receives a de-enrollment file from the Supplier or a new enrollment file from a different Supplier.
- (2) A customer has the right to terminate participation with a Supplier at any time after the unconditional cancellation period, through verbal or written communication with the Supplier. The customer may switch Suppliers or cancel their contract at any time with a Supplier, however the

Continued on Sheet No. F-7.00

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Continued From Sheet No. F-6.00

F2. CUSTOMER PROTECTIONS (Contd.)

however the customer shall be made aware of the existence and amount of any early termination fee by the Supplier. The Supplier shall execute a customer's request for cancellation without delay, irrespective of whether an early termination fee or other penalty is paid to the Supplier.

- (3) A Supplier's sales representatives, agents, or employees must not represent itself in any manner as an employee, affiliate, subcontractor, or agent of the Company. A Supplier's sales representatives, agents, or employees must prominently display identification on the front of their outer clothing that identifies them as employees or agents working on behalf of a Supplier, and includes the name of the Supplier and the name and identification number of the person representing the Supplier. Suppliers must comply with all local ordinances before their sales representatives, agents, or employees begin door-to-door marketing. Door-to-door marketing and telephone marketing must be performed between 9:00 A.M. & 8:00 P.M.
- (4) All contracts offered by the Supplier and signed by the customer must be clearly labeled at the top of the contract as "Gas Customer Choice Contract" with the Supplier's name, the type of contract being offered and in a font size of at least 16 point and bold.
 - (A) A Supplier must use a font size of at least 12 point for its contract with residential and or small commercial customers.
 - (B) All terms and conditions of the contract are considered part of the contract and must be included in the contract document and provided to the customer as one document at the time of signing the contract. The signature can appear on a separate or easily separable document from the terms and conditions as long as the signature page also includes an identifier that is the same as that which appears on the terms and conditions and also includes the customer's name, account number and the language contained in Section F2, paragraph (8), subparagraph (J).
 - (C) Customers enrolling through verbal means shall have the entire contract including the rate, terms and conditions included in the contract provided to them in writing via U.S. mail or verifiable electronic mail. This correspondence shall be postmarked within seven (7) days of the customer's verbal enrollment.
 - (D) Customers enrolling through electronic means shall have the entire contract including the rate, term and conditions included in the contract provided to them in writing via U.S. mail and by verifiable electronic mail. These correspondences shall be postmarked within seven (7) days of the customer's electronic enrollment with the Supplier.
- (5)
 - (A) The maximum early termination fee for residential contracts of one year or less shall not exceed \$50. The maximum early termination fee for residential contracts of longer than one year shall not exceed \$100.
 - (B) The maximum early termination fee for small commercial contracts of one year or less shall not exceed \$150. The maximum early termination fee for small commercial contracts of longer than one year shall not exceed \$250.
- (6) Contracts may continue after initial term expiration on a month-to-month basis, cancelable at any time without penalty.

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F2. CUSTOMER PROTECTIONS (Contd.)

- (7) Any contract that is not signed by the customer or legally authorized person shall be considered null and void. Only the customer account holder or legally authorized person shall be permitted to sign a contract. A Supplier and its agent shall make reasonable inquiries to confirm that the individual signing the contract is a legally authorized person.
- (8) The following information must be included in all residential and commercial Supplier's contracts with a customer:
- (A) The Supplier's name.
 - (B) The Supplier's address.
 - (C) The Supplier's toll-free telephone number.
 - (D) Cancellation rights:
 - (i) All residential and small commercial customers have a 30-day unconditional right to cancel the contract without termination fees following the date the customer signs the contract.
 - (ii) **All Medium** and Large commercial customers have a 14-day unconditional right to cancel the contract without termination fees following the date the customer signs the contract. This class of customer may waive this right of cancellation by affirmatively agreeing to waive this right on the contract. This customer protection waiver should be prominent in the contract language.
 - (E) Any customer fees or penalties related to the contract.
 - (F) The contract pricing provisions in unit rates the customer is typically billed for.
 - (G) The terms regarding contract length.
 - (H) If the Supplier does not offer a fixed price, the contract and all related marketing materials must contain a clear explanation of the pricing factors used to determine the price and an example of how the pricing factors would be implemented.
 - (I) Provision for a 60-day advance notice to the customer of any price change at the expiration of a fixed price contract.
 - (J)
 - (i) Residential Contracts must Include: In bold 14 point type above the place for the customer's signature, the following statement: "I acknowledge that I am the account holder or legally authorized person to execute a contract on behalf of the account holder. I understand that by signing this agreement, I am switching the gas Supplier for this account to (new Supplier name). I understand that gas purchased for this account by (new Supplier name) will be delivered through Michigan Gas Utilities' delivery system. The account holder, or the person who signed this contract on behalf of the account holder, has 30-days after today to cancel this contract for any reason through written or verbal notification to (new Supplier name)."
 - (ii) Small Commercial Contracts must include: In bold 12 point type above the place for the legally authorized customer's signature and company business title, the following statement: "I acknowledge that I am the account holder or legally authorized person to execute a contract and legally bind the business in this contract. I understand that by signing this contract, I am switching the gas Supplier for this commercial account to (new Supplier name). I understand

Continued on Sheet No. F-9.00

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F2. CUSTOMER PROTECTIONS (Contd.)

that gas purchased for this commercial account by (new Supplier name) will be delivered through Michigan Gas Utilities' delivery system. The legally authorized person to execute a contract and legally bind the business in this contract, has 30-days after today to cancel this contract for any reason through written or verbal notification to (new Supplier name)."

- (iii) Medium and Large Commercial Contract must include: In bold 12 point type above the place for the legally authorized customer's signature and company business title, the following statement: "I acknowledge that I am the account holder or legally authorized person to execute a contract and legally bind the business in this contract. I understand that by signing this contract, I am switching the gas Supplier for this commercial account to (new Supplier name). I understand that gas purchased for this commercial account by (new Supplier name) will be delivered through Michigan Gas Utilities' delivery system. The legally authorized person to execute a contract and legally bind the business in this contract, has 14-days after today to cancel this contract for any reason through written or verbal notification to (new Supplier name). I may waive this right of cancellation by affirmatively agreeing to this waiver on the contract. If you terminated your contract today, and if the unconditional cancellation period did not apply, based on current gas prices and your historical usage, a good-faith estimate of your termination fee would be (AGS places its fee here). This termination fee is subject to change as your usage and the market price of gas fluctuate."

- (9) A Supplier must allow the Commission Staff an opportunity to review and comment on its residential and small commercial contract(s), marketing materials and scripts at least five business days before the Supplier intends to use the contract(s) and marketing materials in the marketplace.
- (10) A Supplier that does not comply with the requirements of Section F of this tariff will have its participation in the Program suspended until the Commission or its Staff has determined that necessary changes have been made to comply with the requirements. Any continuing or further non-compliance or use of materials that the Commission or its Staff determines do not meet all of the requirements of Section F of this tariff may result in the Supplier's termination from the Program.
- (11) A Supplier must distribute a confirmation letter to residential customers by U.S. mail. The confirmation letter must be postmarked within seven (7) days of the customer or legally authorized person signing a contract with the Supplier. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, the fixed or variable rate charged, the unconditional cancellation period, any early termination fee, the Supplier's toll-free number, the Commission's toll-free number and any safety-related messages required by the Company. The confirmation letter may be sent with the contract in cases where a contract must be sent. The Company is not required to distribute letters to customers confirming a customer's choice of an alternative Supplier.

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F2. CUSTOMER PROTECTIONS (Contd.)

A supplier must distribute a confirmation letter to all commercial customers by certified U.S. mail, verifiable facsimile or verifiable electronic mail within seven (7) days of the customer or legally authorized person signing a contract with the Supplier. The supplier shall be responsible for maintaining records that verify delivery and receipt of the confirmation letter, facsimile or E-mail. The confirmation letter must be sent to the business's principal office. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, fixed or variable rate charged, the unconditional cancellation period, if any, any early termination fee, the Supplier's toll-free number, the Commission's toll-free number and any safety-related messages required by the Company. Suppliers must include a good-faith estimate of the Large Commercial customer's early termination fee, identifying the applicable pricing factors and an example of how the fee is calculated.

F3. SOLICITATION REQUIREMENTS

DEFINITIONS:

Alternative Gas Supplier (AGS) or Supplier means a marketer, broker, producer, or other entity that has received a license from the Commission and executed an Authorized Gas Supplier Agreement with the Company to deliver gas supplies to customers under Rate CC.

Customer:

- Residential means a purchaser (account holder) of natural gas that is supplied or distributed by a utility for residential purposes.
- Small Commercial means a non-residential customer (business name) with usage of ~~500~~ **3,300** Mcf of natural gas or less per year.
- **Medium Commercial means a non-residential customer (business name) with usage of 3,300 to 8,300 Mcf of natural gas or less per year.**
- Large Commercial means a non-residential customer (business name) with usage above ~~500~~ **8,300** Mcf of natural gas per year that is supplied or distributed by a utility for non-residential purposes.

Legally Authorized Person means the person that has legal documentation or legal authority to enroll a residential or commercial customer into a binding contract. A legally authorized person includes, but is not limited to, an individual with power of attorney or a corporate agent authorized to enter into contracts on a corporation's behalf.

Program means the Gas Customer Choice Program approved by the Commission.

The terms "signature" or "signed" includes electronic signatures as defined in the Michigan Uniform Electronic Transactions Act.

These provisions shall be monitored and enforced solely by the Commission or its Staff.

- (1) It is the Supplier's responsibility to have a current valid contract with the customer at all times. The Commission or its Staff may request a reasonable number of records from a Supplier to verify compliance with this customer verification provision and, in addition, may request

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F3. SOLICITATION REQUIREMENTS (Contd.)

records for any customer due to a dispute. For each customer, a Supplier must be able to demonstrate that a customer has made a knowing selection of the Supplier by at least one of the following verification records:

- (A) An original signature from the customer or legally authorized person.
- (B) Independent third party verification with an audio recording of the entire verification call.
- (C) An E-mail address if signed-up through the Internet.

- (2) Suppliers and agents who are soliciting customers must comply with the following requirements:

- (A) The Supplier and its agents must clearly identify the AGS on whose behalf they are soliciting.
- (B) The Supplier and its agents must not represent themselves as employees or agents of the Company.
- (C) The Supplier and its agents must affirmatively indicate if they are a marketing affiliate of the Company, that the affiliate is a separate entity and that the affiliate is not regulated by the Michigan Public Service Commission.
- (D) The Supplier and its agents must submit residential and small commercial contract(s), marketing materials and scripts to the Commission Staff for review at least five (5) business days prior to using the materials in the marketplace.
- (E) The Supplier and its agents cannot remove the original of the customer's bill from the residence, or small commercial office or medium commercial office.
- (F) The Supplier and its agents must comply with truth in advertising in all verbal, written, or electronic statements to the customer.
- (G) A Supplier who is actively marketing and/or enrolling customers in the Company's territory will post to the Commission's gas rate comparison website at MI.gov/CompareMIGas its generally available offers for residential, and small commercial customers and medium commercial customers per the Terms and Conditions of the AGS licensing application.

- (3) A Supplier must provide a copy of the contract to the customer, including all terms and conditions. The contract must contain all provisions as set forth in Section F2.

F4. SUPPLIER LICENSING AND CODE OF CONDUCT

DEFINITIONS:

Alternative Gas Supplier (AGS) or Supplier means a marketer, broker, producer, or other entity that has received a license from the Commission and executed an Authorized Gas Supplier Agreement with the Company to deliver gas supplies to customers under Rate CC.

Customer:

- Residential means a purchaser (account holder) of natural gas that is supplied or distributed by a utility for residential purposes.
- Small Commercial means a non-residential customer (business name) with usage ~~of 500~~ less than 3,300 Mcf of natural gas or less per year.
- Medium Commercial means a non-residential customer (business name) with usage of 3,300 – 8,300 Mcf of natural gas or less per year.
- Large Commercial means a non-residential customer (business name) with usage above ~~500~~ 8,300 Mcf of natural gas per year that is supplied or distributed by a utility for non-residential purposes.

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Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
1	(1) PRODUCTION EXPENSES					
2	A. Gas Steam Production					
3	Operation:					
4	(700) Operation Supervision & Engineering	-	-	-	-	
5	(701) Operation Labor	-	-	-	-	
6	(702) Boiler Fuel	-	-	-	-	
7	(703) Miscellaneous Steam Expenses	-	-	-	-	
8	(704) Transferred-Credit	-	-	-	-	
9						
10	TOTAL Operation	-	-	-	-	
11						
12	Maintenance:					
13	(705) Maintenance Supervision & Engineering	-	-	-	-	
14	(706) Maintenance of Structures & Improvements	-	-	-	-	
15	(707) Maintenance of Boiler Plant Equipment	-	-	-	-	
16	(708) Maint of Oth Strm ProdPit	-	-	-	-	
17						
18	TOTAL Maintenance	-	-	-	-	
19	TOTAL Production Expenses-Gas Steam	-	-	-	-	
20						
21	B. Liquified Gas Production					
22	Operation:					
23	(710) Operation Supervision & Engineering	-	-	-	-	
24	(711) Steam Expenses	-	-	-	-	
25	(712) Other Power Expenses	-	-	-	-	
26	(717) Petroleum Gas Expenses	-	-	-	-	
27	(728) Petroleum Gas	-	-	-	-	
28	(732) Purification Expenses	-	-	-	-	
29	(735) Miscellaneous Production Expenses	888	944	37	981	MGP Amortization
30	(736) Rents	-	-	-	-	
31						
32	TOTAL Operation	888	944	37	981	
33						
34	Maintenance:					
35	(740) Maintenance Supervision & Engineering	-	-	-	-	
36	(741) Maintenance of Structures & Improvements	-	-	-	-	
37	(742) Maintenance of Production Equipment	-	-	-	-	
38						
39	TOTAL Maintenance	-	-	-	-	
40	TOTAL Production Expenses-Liquified Gas	888	944	37	981	

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
41						
42	C. Natural Gas Production					
43	Operation:					
44	(754) Field Compressor Station	-	-	-	-	
45	(756) Field Measuring & Regulating Station	-	-	-	-	
46						
47	TOTAL Operation	-	-	-	-	
48						
49	Maintenance:					
50						
51						
52	TOTAL Maintenance	-	-	-	-	
53	TOTAL Production Expenses-Natural Gas	-	-	-	-	
54						
55	D. Other Gas Supply Expenses					
56	Operation:					
57	(800) Natural Gas Well Head Purchases	-	-	-	-	
58	(804) Natural Gas City Gas Purchases	378	410	-	410	
59	(805) Other Gas Purchases	-	-	-	-	
60	(808.1) Gas Withdrawn From Storage-Debit	-	-	-	-	
61	(808.2) Gas Delivered to Storage-Credit	-	-	-	-	
62	(810) Gas Used for Compress Station Fuel	-	-	-	-	
63	(812) Gas Used for Other Operations-Credit	-	-	-	-	
64	(813) Other Gas Supply Expenses	1	1	-	1	
65						
66	TOTAL Operation	380	412	-	412	
67						
68	Maintenance:					
69		-	-	-	-	
70						
71	TOTAL Maintenance	-	-	-	-	
72	TOTAL Production Expenses-Other Gas Supply	380	412	-	412	
73						
74	TOTAL PRODUCTION EXPENSES	1,267	1,356	37	1,393	

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
75	(2) NATURAL GAS STORAGE					
76	Operation:					
77	(814) Operation Supervision & Engineering	83	90	-	90	
78	(815) Maps & Records	-	-	-	-	
79	(816) Wells	74	80	30	110	Corrosion Logs (Partello)
80	(817) Lines Expense	41	44	-	44	
81	(818) Compressor Station	22	23	-	23	
82	(819) Compress Station F&Pwr	-	-	-	-	
83	(820) Measuring & Regulating Station	1	1	-	1	
84	(821) Purification Expenses	11	12	-	12	
85	(824) Other Expenses	161	172	50	222	SIMP Implementation (Partello)
86						
87	TOTAL Operation	392	422	80	502	
88						
89	Maintenance:					
90	(830) Maintenance Supervision & Engineering	5	6	-	6	
91	(832) Maintenance Reservoirs & Wells	17	18	-	18	
92	(833) Maintenance of Lines	4	5	-	5	
93	(834) Maintenance Compressor Station Equipment	31	33	-	33	
94	(835) Maintenance Measuring & Regulating Equipment	-	-	-	-	
95	(836) Maintenance Purification Equipment	12	13	-	13	
96	(837) Maintenance Other Equipment	2	2	-	2	
97	(842) Other Storage-Fuel	-	-	-	-	
98						
99	TOTAL Maintenance	71	76	-	76	
100	TOTAL Natural Gas Storage Expenses	463	498	80	578	
101						
102	(3) TRANSMISSION EXPENSES					
103	Operation:					
104	(850) Operation Supervision & Engineering	11	12	-	12	
105	(851) Sys Cont & Load Disp	-	-	-	-	
106	(854) Gas For Compressor Station Fuel	71	75	-	75	
107	(856) Mains Exp	29	31	175	206	Casing Vent Replacements
108	(857) Measuring & Regulating Station	177	189	-	189	
109	(859) Other Expenses	51	54	20	74	Gas Sampling
110						
111	TOTAL Operation	339	362	195	557	
112						
113	Maintenance:					
114	(863) Maintenance of Mains	33	35	50	85	New TIMP Rules
115	(865) Maintenance Measuring & Regulating Equipment	107	115	-	115	
116	(867) Maintenance Other Equipment	-	-	-	-	
117						
118	TOTAL Maintenance	139	151	50	201	
119	TOTAL Transmission Expenses	478	512	245	757	

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
120						
121	(4) DISTRIBUTION EXPENSES					
122	Operation:					
123	(870) Operation Supervision & Engineering	1,026	1,111	-	1,111	
124	(871) Distribution Load Dispatching	303	329	-	329	
						Isolated Steel Services, Locators, Damage Prevention, Pipeline Safety Management System
125	(874) Mains and Services Expenses	1,878	2,030	314	2,344	
126	(875) Measuring & Regulating Station Equipment	15	17	-	17	
127	(877) Measuring & Regulating Station Equipment-City Gate Check Static	207	224	-	224	
128	(878) Meter & House Regulator Expense	607	656	-	656	
129	(879) Customer Installations Expense	729	789	-	789	
130	(880) Other Expenses	2,254	2,429	237	2,666	Deferred Maintenance of Facilities
131	(881) Rents	(13)	(14)	-	(14)	
132						
133	TOTAL Operation	7,006	7,569	551	8,120	
134						
135	Maintenance:					
136	(885) Maintenance Supervision & Engineering	19	21	-	21	
137	(887) Maintenance of Mains	581	627	100	727	Exposed Main Under Bridges Structure Painting, Station Painting
138	(889) Maintenance of Measuring & Regulating Station	82	89	450	539	
139	(891) Maintenance of Measuring & Regulating Gate Station Equipment	135	144	-	144	
140	(892) Maintenance of Services	210	226	680	906	Cross Bores
141	(893) Maintenance of Meters & House Regulators	285	308	258	566	Painting and Maintenance
142	(894) Maintenance of Other Equipment	356	382	-	382	
143						
144	TOTAL Maintenance	1,668	1,798	1,488	3,286	
145	TOTAL Distribution Expenses	8,675	9,367	2,039	11,406	
146						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
147	(5) CUSTOMER ACCOUNTS EXPENSES					
148	Operation:					
149	(901) Supervision	184	199	-	199	
150	(902) Meter Reading Expenses	1,944	2,093	(1,487)	606	AMI
151	(903) Customer Records and Collection Expenses	4,821	5,149	20	5,169	
152	(904) Uncollectible Accounts	1,545	1,644	268	1,912	Uncollectible Accounts
153	(905) Miscellaneous Customer Accounts Expenses	68	74	-	74	
154	TOTAL Customer Accounts Expenses	8,562	9,159	(1,199)	7,960	
155						
156	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
157	Operation:					
158	(907) Supervision	17	18	-	18	
159	(908) Customer Assistance Expenses	476	515	-	515	
160	(909) Informational and Instructional Expenses	86	92	-	92	
161	(910) Miscellaneous Customer Service and Informational Expenses	-	-	-	-	
162	TOTAL Cust. Service and Informational Expenses	579	625	-	625	
163						
164	(7) SALES EXPENSES					
165	Operation:					
166	(911) Supervision	-	-	-	-	
167	(912) Demonstrating and Selling Expenses	-	-	-	-	
168	(913) Advertising Expenses	2	2	-	2	
169	(916) Miscellaneous Sales Expenses	-	-	-	-	
170	TOTAL Sales Expenses	2	2	-	2	
171						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted

Line No.		2019 Historical Total O&M	2022 Forecasted Total O&M Not Including K&M	K&M	2022 Forecasted Total O&M Including K&M	K&M Reason
172	(8) ADMINISTRATIVE AND GENERAL EXPENSES					
173	Operation:					
174	(920) Administrative and General Salaries	2,687	2,916	-	2,916	
175	(921) Office Supplies and Expenses	903	960	-	960	
176	(922) Administrative Expenses Transferred-Credit	-	-	-	-	
177	(923) Outside Services Employed	354	376	-	376	
178	(924) Property Insurance	34	37	-	37	
179	(925) Injuries and Damages	488	520	67	586	Injuries & Damages
180	(926) Employee Pensions and Benefits	4,312	4,586	533	5,120	Pension & Benefits
181	(927) Franchise Requirements	-	-	-	-	
182	(928) Regulatory Commission Expenses	599	642	-	642	
183	(929) Duplicate Charges-Cr.	-	-	-	-	
184	(930) Advertising Expenses	-	-	-	-	
185	(930.1) General Advertising Expenses	-	-	-	-	
186	(930.2) Miscellaneous General Expenses	1,093	1,163	(26)	1,137	Return On/Of
187	(931) Rents	442	470	-	470	
188	TOTAL Operation	10,911	11,670	573	12,243	
189						
190	Maintenance:					
191	(935) Maintenance of General Plant	-	-	-	-	
192	TOTAL Maintenance	-	-	-	-	
193	TOTAL Administrative and General Expenses	10,911	11,670	573	12,243	
194						
195	Operation and Maintenance Expenses	30,937	33,189	1,776	34,964	
196						
197						
198						
199	Total Operations and Maintenance Expense	30,937	33,189	1,776	34,964	

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
1	(1) PRODUCTION EXPENSES					
2	A. Gas Steam Production					
3	Operation:					
4	(700) Operation Supervision & Engineering	-	2.530%	2.800%	2.980%	-
5	(701) Operation Labor	-	2.530%	2.800%	2.980%	-
6	(702) Boiler Fuel	-	2.530%	2.800%	2.980%	-
7	(703) Miscellaneous Steam Expenses	-	2.530%	2.800%	2.980%	-
8	(704) Transferred-Credit	-	2.530%	2.800%	2.980%	-
9						
10	TOTAL Operation	-				-
11						
12	Maintenance:					
13	(705) Maintenance Supervision & Engineering	-	2.530%	2.800%	2.980%	-
14	(706) Maintenance of Structures & Improvements	-	2.530%	2.800%	2.980%	-
15	(707) Maintenance of Boiler Plant Equipment	-	2.530%	2.800%	2.980%	-
16	(708) Maint of Oth Strm ProdPlt	-	2.530%	2.800%	2.980%	-
17						
18	TOTAL Maintenance	-				-
19	TOTAL Production Expenses-Gas Steam	-				-
20						
21	B. Liquified Gas Production					
22	Operation:					
23	(710) Operation Supervision & Engineering	-	2.530%	2.800%	2.980%	-
24	(711) Steam Expenses	-	2.530%	2.800%	2.980%	-
25	(712) Other Power Expenses	-	2.530%	2.800%	2.980%	-
26	(717) Petroleum Gas Expenses	-	2.530%	2.800%	2.980%	-
27	(728) Petroleum Gas	-	2.530%	2.800%	2.980%	-
28	(732) Purification Expenses	-	2.530%	2.800%	2.980%	-
29	(735) Miscellaneous Production Expenses	-	2.530%	2.800%	2.980%	-
30	(736) Rents	-	2.530%	2.800%	2.980%	-
31						
32	TOTAL Operation	-				-
33						
34	Maintenance:					
35	(740) Maintenance Supervision & Engineering	-	2.530%	2.800%	2.980%	-
36	(741) Maintenance of Structures & Improvements	-	2.530%	2.800%	2.980%	-
37	(742) Maintenance of Production Equipment	-	2.530%	2.800%	2.980%	-
38						
39	TOTAL Maintenance	-				-
40	TOTAL Production Expenses-Liquified Gas	-				-

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
41						
42	C. Natural Gas Production					
43	Operation:					
44	(754) Field Compressor Station	-	2.530%	2.800%	2.980%	-
45	(756) Field Measuring & Regulating Station	-	2.530%	2.800%	2.980%	-
46						
47	TOTAL Operation	-				-
48						
49	Maintenance:					-
50		-	2.530%	2.800%	2.980%	-
51						
52	TOTAL Maintenance	-				-
53	TOTAL Production Expenses-Natural Gas	-				-
54						
55	D. Other Gas Supply Expenses					
56	Operation:					
57	(800) Natural Gas Well Head Purchases	-	2.530%	2.800%	2.980%	-
58	(804) Natural Gas City Gas Purchases	359	2.530%	2.800%	2.980%	390
59	(805) Other Gas Purchases	-	2.530%	2.800%	2.980%	-
60	(808.1) Gas Withdrawn From Storage-Debit	-	2.530%	2.800%	2.980%	-
61	(808.2) Gas Delivered to Storage-Credit	-	2.530%	2.800%	2.980%	-
62	(810) Gas Used for Compress Station Fuel	-	2.530%	2.800%	2.980%	-
63	(812) Gas Used for Other Operations-Credit	-	2.530%	2.800%	2.980%	-
64	(813) Other Gas Supply Expenses	1	2.530%	2.800%	2.980%	1
65						
66	TOTAL Operation	361				392
67						
68	Maintenance:					-
69		-	2.530%	2.800%	2.980%	-
70						
71	TOTAL Maintenance	-				-
72	TOTAL Production Expenses-Other Gas Supply	361				392
73						
74	TOTAL PRODUCTION EXPENSES	361				392

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
75	(2) NATURAL GAS STORAGE					
76	Operation:					
77	(814) Operation Supervision & Engineering	76	2.530%	2.800%	2.980%	82
78	(815) Maps & Records	-	2.530%	2.800%	2.980%	-
79	(816) Wells	31	2.530%	2.800%	2.980%	34
80	(817) Lines Expense	21	2.530%	2.800%	2.980%	23
81	(818) Compressor Station	14	2.530%	2.800%	2.980%	15
82	(819) Compress Station F&Pwr	-	2.530%	2.800%	2.980%	-
83	(820) Measuring & Regulating Station	1	2.530%	2.800%	2.980%	1
84	(821) Purification Expenses	9	2.530%	2.800%	2.980%	10
85	(824) Other Expenses	64	2.530%	2.800%	2.980%	70
86						
87	TOTAL Operation	217				235
88						
89	Maintenance:					
90	(830) Maintenance Supervision & Engineering	4	2.530%	2.800%	2.980%	5
91	(832) Maintenance Reservoirs & Wells	5	2.530%	2.800%	2.980%	5
92	(833) Maintenance of Lines	1	2.530%	2.800%	2.980%	1
93	(834) Maintenance Compressor Station Equipment	10	2.530%	2.800%	2.980%	11
94	(835) Maintenance Measuring & Regulating Equipment	-	2.530%	2.800%	2.980%	-
95	(836) Maintenance Purification Equipment	5	2.530%	2.800%	2.980%	6
96	(837) Maintenance Other Equipment	1	2.530%	2.800%	2.980%	1
97	(842) Other Storage-Fuel	-	2.530%	2.800%	2.980%	-
98		-				-
99	TOTAL Maintenance	26				28
100	TOTAL Natural Gas Storage Expenses	243				264
101						
102	(3) TRANSMISSION EXPENSES					
103	Operation:					
104	(850) Operation Supervision & Engineering	9	2.530%	2.800%	2.980%	10
105	(851) Sys Cont & Load Disp	-	2.530%	2.800%	2.980%	-
106	(854) Gas For Compressor Station Fuel	-	2.530%	2.800%	2.980%	-
107	(856) Mains Exp	16	2.530%	2.800%	2.980%	18
108	(857) Measuring & Regulating Station	11	2.530%	2.800%	2.980%	12
109	(859) Other Expenses	1	2.530%	2.800%	2.980%	1
110		-				-
111	TOTAL Operation	38				42
112						
113	Maintenance:					
114	(863) Maintenance of Mains	28	2.530%	2.800%	2.980%	30
115	(865) Maintenance Measuring & Regulating Equipment	84	2.530%	2.800%	2.980%	92
116	(867) Maintenance Other Equipment	-	2.530%	2.800%	2.980%	-
117						
118	TOTAL Maintenance	112				122
119	TOTAL Transmission Expenses	151				164

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
120						
121	(4) DISTRIBUTION EXPENSES					
122	Operation:					
123	(870) Operation Supervision & Engineering	876	2.530%	2.800%	2.980%	950
124	(871) Distribution Load Dispatching	289	2.530%	2.800%	2.980%	313
125	(874) Mains and Services Expenses	1,470	2.530%	2.800%	2.980%	1,596
126	(875) Measuring & Regulating Station Equipment	14	2.530%	2.800%	2.980%	15
127	(877) Measuring & Regulating Station Equipment-City Gate Check Static	143	2.530%	2.800%	2.980%	155
128	(878) Meter & House Regulator Expense	520	2.530%	2.800%	2.980%	565
129	(879) Customer Installations Expense	629	2.530%	2.800%	2.980%	683
130	(880) Other Expenses	1,434	2.530%	2.800%	2.980%	1,556
131	(881) Rents	0	2.530%	2.800%	2.980%	0
132						
133	TOTAL Operation	5,375				5,834
134						
135	Maintenance:					
136	(885) Maintenance Supervision & Engineering	17	2.530%	2.800%	2.980%	18
137	(887) Maintenance of Mains	434	2.530%	2.800%	2.980%	471
138	(889) Maintenance of Measuring & Regulating Station	60	2.530%	2.800%	2.980%	66
139	(891) Maintenance of Measuring & Regulating Gate Station Equipment	54	2.530%	2.800%	2.980%	58
140	(892) Maintenance of Services	119	2.530%	2.800%	2.980%	130
141	(893) Maintenance of Meters & House Regulators	222	2.530%	2.800%	2.980%	241
142	(894) Maintenance of Other Equipment	146	2.530%	2.800%	2.980%	158
143						
144	TOTAL Maintenance	1,053				1,143
145	TOTAL Distribution Expenses	6,428				6,977
146						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
147	(5) CUSTOMER ACCOUNTS EXPENSES					
148	Operation:					
149	(901) Supervision	183	2.530%	2.800%	2.980%	199
150	(902) Meter Reading Expenses	1,128	2.530%	2.800%	2.980%	1,224
151	(903) Customer Records and Collection Expenses	991	2.530%	2.800%	2.980%	1,076
152	(904) Uncollectible Accounts	-	2.530%	2.800%	2.980%	-
153	(905) Miscellaneous Customer Accounts Expenses	51	2.530%	2.800%	2.980%	55
154	TOTAL Customer Accounts Expenses	2,353				2,554
155						
156	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
157	Operation:					
158	(907) Supervision	15	2.530%	2.800%	2.980%	17
159	(908) Customer Assistance Expenses	403	2.530%	2.800%	2.980%	437
160	(909) Informational and Instructional Expenses	-	2.530%	2.800%	2.980%	-
161	(910) Miscellaneous Customer Service and Informational Expenses	-	2.530%	2.800%	2.980%	-
162	TOTAL Cust. Service and Informational Expenses	418				454
163						
164	(7) SALES EXPENSES					
165	Operation:					
166	(911) Supervision	-	2.530%	2.800%	2.980%	-
167	(912) Demonstrating and Selling Expenses	-	2.530%	2.800%	2.980%	-
168	(913) Advertising Expenses	-	2.530%	2.800%	2.980%	-
169	(916) Miscellaneous Sales Expenses	-	2.530%	2.800%	2.980%	-
170	TOTAL Sales Expenses	-				-
171						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Labor

Line No.		2019 Historical Total Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Labor O&M Not Including K&M
172	(8) ADMINISTRATIVE AND GENERAL EXPENSES					
173	Operation:					
174	(920) Administrative and General Salaries	2,675	2.530%	2.800%	2.980%	2,903
175	(921) Office Supplies and Expenses	-	2.530%	2.800%	2.980%	-
176	(922) Administrative Expenses Transferred-Credit	-	2.530%	2.800%	2.980%	-
177	(923) Outside Services Employed	-	2.530%	2.800%	2.980%	-
178	(924) Property Insurance	-	2.530%	2.800%	2.980%	-
179	(925) Injuries and Damages	-	2.530%	2.800%	2.980%	-
180	(926) Employee Pensions and Benefits	-	2.530%	2.800%	2.980%	-
181	(927) Franchise Requirements	-	2.530%	2.800%	2.980%	-
182	(928) Regulatory Commission Expenses	224	2.530%	2.800%	2.980%	244
183	(929) Duplicate Charges-Cr.	-	2.530%	2.800%	2.980%	-
184	(930) Advertising Expenses	-	2.530%	2.800%	2.980%	-
185	(930.1) General Advertising Expenses	-	2.530%	2.800%	2.980%	-
186	(930.2) Miscellaneous General Expenses	36	2.530%	2.800%	2.980%	39
187	(931) Rents	3	2.530%	2.800%	2.980%	3
188	TOTAL Operation	2,938				3,189
189						
190	Maintenance:					
191	(935) Maintenance of General Plant	-	2.530%	2.800%	2.980%	-
192	TOTAL Maintenance	-				-
193	TOTAL Administrative and General Expenses	2,938				3,189
194						
195	TOTAL Operation and Maintenance Expenses	12,891				13,992

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Line No.		2019 Historical Total Non-Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Non-Labor O&M Not Including K&M
1	(1) PRODUCTION EXPENSES					
2	A. Gas Steam Production					
3	Operation:					
4	(700) Operation Supervision & Engineering	-	1.595%	2.375%	2.275%	-
5	(701) Operation Labor	-	1.595%	2.375%	2.275%	-
6	(702) Boiler Fuel	-	1.595%	2.375%	2.275%	-
7	(703) Miscellaneous Steam Expenses	-	1.595%	2.375%	2.275%	-
8	(704) Transferred-Credit	-	1.595%	2.375%	2.275%	-
9						
10	TOTAL Operation	-				-
11						
12	Maintenance:					
13	(705) Maintenance Supervision & Engineering	-	1.595%	2.375%	2.275%	-
14	(706) Maintenance of Structures & Improvements	-	1.595%	2.375%	2.275%	-
15	(707) Maintenance of Boiler Plant Equipment	-	1.595%	2.375%	2.275%	-
16	(708) Maint of Oth Stm ProdPlt	-	1.595%	2.375%	2.275%	-
17						
18	TOTAL Maintenance	-				-
19	TOTAL Production Expenses-Gas Steam	-				-
20						
21	B. Liquefied Gas Production					
22	Operation:					
23	(710) Operation Supervision & Engineering	-	1.595%	2.375%	2.275%	-
24	(711) Steam Expenses	-	1.595%	2.375%	2.275%	-
25	(712) Other Power Expenses	-	1.595%	2.375%	2.275%	-
26	(717) Petroleum Gas Expenses	-	1.595%	2.375%	2.275%	-
27	(728) Petroleum Gas	-	1.595%	2.375%	2.275%	-
28	(732) Purification Expenses	-	1.595%	2.375%	2.275%	-
29	(735) Miscellaneous Production Expenses	888	1.595%	2.375%	2.275%	944
30	(736) Rents	-	1.595%	2.375%	2.275%	-
31						
32	TOTAL Operation	888				944
33						
34	Maintenance:					
35	(740) Maintenance Supervision & Engineering	-	1.595%	2.375%	2.275%	-
36	(741) Maintenance of Structures & Improvements	-	1.595%	2.375%	2.275%	-
37	(742) Maintenance of Production Equipment	-	1.595%	2.375%	2.275%	-
38						
39	TOTAL Maintenance	-				-
40	TOTAL Production Expenses-Liquefied Gas	888				944

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Historical and Forecasted - Non Labor						
	2019 Historical Total Non-Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Non-Labor O&M Not Including K&M	
Line No.						
41						
42	C. Natural Gas Production					
43	Operation:					
44	(754) Field Compressor Station	-	1.595%	2.375%	2.275%	-
45	(756) Field Measuring & Regulating Station	-	1.595%	2.375%	2.275%	-
46						
47	TOTAL Operation	-				-
48						
49	Maintenance:					-
50		-	1.595%	2.375%	2.275%	-
51						
52	TOTAL Maintenance	-				-
53	TOTAL Production Expenses-Natural Gas	-				-
54						
55	D. Other Gas Supply Expenses					
56	Operation:					
57	(800) Natural Gas Well Head Purchases	-	1.595%	2.375%	2.275%	-
58	(804) Natural Gas City Gas Purchases	19	1.595%	2.375%	2.275%	20
59	(805) Other Gas Purchases	-	1.595%	2.375%	2.275%	-
60	(808.1) Gas Withdrawn From Storage-Debit	-	1.595%	2.375%	2.275%	-
61	(808.2) Gas Delivered to Storage-Credit	-	1.595%	2.375%	2.275%	-
62	(810) Gas Used for Compress Station Fuel	-	1.595%	2.375%	2.275%	-
63	(812) Gas Used for Other Operations-Credit	-	1.595%	2.375%	2.275%	-
64	(813) Other Gas Supply Expenses	0	1.595%	2.375%	2.275%	0
65						
66	TOTAL Operation	19				20
67						
68	Maintenance:					-
69		-	1.595%	2.375%	2.275%	-
70						
71	TOTAL Maintenance	-				-
72	TOTAL Production Expenses-Other Gas Supply	19				20
73						
74	TOTAL PRODUCTION EXPENSES	907				964

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Line No.		2019	2020	2021	2022	2022 Forecasted
		Historical Total Non-Labor O&M				Total Non-Labor O&M Not Including K&M
75	(2) NATURAL GAS STORAGE					
76	Operation:					
77	(814) Operation Supervision & Engineering	7	1.595%	2.375%	2.275%	7
78	(815) Maps & Records	-	1.595%	2.375%	2.275%	-
79	(816) Wells	43	1.595%	2.375%	2.275%	46
80	(817) Lines Expense	19	1.595%	2.375%	2.275%	21
81	(818) Compressor Station	8	1.595%	2.375%	2.275%	9
82	(819) Compress Station F&Pwr	-	1.595%	2.375%	2.275%	-
83	(820) Measuring & Regulating Station	0	1.595%	2.375%	2.275%	0
84	(821) Purification Expenses	2	1.595%	2.375%	2.275%	2
85	(824) Other Expenses	96	1.595%	2.375%	2.275%	102
86		-				
87	TOTAL Operation	176				187
88						
89	Maintenance:					
90	(830) Maintenance Supervision & Engineering	1	1.595%	2.375%	2.275%	1
91	(832) Maintenance Reservoirs & Wells	12	1.595%	2.375%	2.275%	13
92	(833) Maintenance of Lines	4	1.595%	2.375%	2.275%	4
93	(834) Maintenance Compressor Station Equipment	20	1.595%	2.375%	2.275%	22
94	(835) Maintenance Measuring & Regulating Equipment	-	1.595%	2.375%	2.275%	-
95	(836) Maintenance Purification Equipment	7	1.595%	2.375%	2.275%	7
96	(837) Maintenance Other Equipment	1	1.595%	2.375%	2.275%	1
97	(842) Other Storage-Fuel	-	1.595%	2.375%	2.275%	-
98		-				
99	TOTAL Maintenance	44				47
100	TOTAL Natural Gas Storage Expenses	220				234
101						
102	(3) TRANSMISSION EXPENSES					
103	Operation:					
104	(850) Operation Supervision & Engineering	2	1.595%	2.375%	2.275%	2
105	(851) Sys Cont & Load Disp	-	1.595%	2.375%	2.275%	-
106	(854) Gas For Compressor Station Fuel	71	1.595%	2.375%	2.275%	75
107	(856) Mains Exp	13	1.595%	2.375%	2.275%	13
108	(857) Measuring & Regulating Station	166	1.595%	2.375%	2.275%	177
109	(859) Other Expenses	49	1.595%	2.375%	2.275%	53
110		-				
111	TOTAL Operation	301				320
112						
113	Maintenance:					
114	(863) Maintenance of Mains	5	1.595%	2.375%	2.275%	5
115	(865) Maintenance Measuring & Regulating Equipment	22	1.595%	2.375%	2.275%	24
116	(867) Maintenance Other Equipment	-	1.595%	2.375%	2.275%	-
117						
118	TOTAL Maintenance	27				29
119	TOTAL Transmission Expenses	328				348

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Line No.		2019	2020	2021	2022	2022 Forecasted
		Historical Total Non-Labor O&M				Total Non-Labor O&M Not Including K&M
			CPI	CPI		
120						
121	(4) DISTRIBUTION EXPENSES					
122	Operation:					
123	(870) Operation Supervision & Engineering	151	1.595%	2.375%	2.275%	160
124	(871) Distribution Load Dispatching	14	1.595%	2.375%	2.275%	15
125	(874) Mains and Services Expenses	408	1.595%	2.375%	2.275%	434
126	(875) Measuring & Regulating Station Equipment	2	1.595%	2.375%	2.275%	2
127	(877) Measuring & Regulating Station Equipment-City Gate Check Static	64	1.595%	2.375%	2.275%	68
128	(878) Meter & House Regulator Expense	86	1.595%	2.375%	2.275%	92
129	(879) Customer Installations Expense	99	1.595%	2.375%	2.275%	106
130	(880) Other Expenses	820	1.595%	2.375%	2.275%	872
131	(881) Rents	(13)	1.595%	2.375%	2.275%	(14)
132						
133	TOTAL Operation	1,631				1,735
134						
135	Maintenance:					
136	(885) Maintenance Supervision & Engineering	2	1.595%	2.375%	2.275%	2
137	(887) Maintenance of Mains	146	1.595%	2.375%	2.275%	156
138	(889) Maintenance of Measuring & Regulating Station	22	1.595%	2.375%	2.275%	23
139	(891) Maintenance of Measuring & Regulating Gate Station Equipment	81	1.595%	2.375%	2.275%	86
140	(892) Maintenance of Services	91	1.595%	2.375%	2.275%	97
141	(893) Maintenance of Meters & House Regulators	63	1.595%	2.375%	2.275%	67
142	(894) Maintenance of Other Equipment	211	1.595%	2.375%	2.275%	224
143		-				
144	TOTAL Maintenance	616				655
145	TOTAL Distribution Expenses	2,247				2,390
146						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Line No.		2019 Historical Total Non-Labor O&M	2020 CPI	2021 CPI	2022	2022 Forecasted Total Non-Labor O&M Not Including K&M
147	(5) CUSTOMER ACCOUNTS EXPENSES					
148	Operation:					
149	(901) Supervision	1	1.595%	2.375%	2.275%	1
150	(902) Meter Reading Expenses	816	1.595%	2.375%	2.275%	868
151	(903) Customer Records and Collection Expenses	3,830	1.595%	2.375%	2.275%	4,074
152	(904) Uncollectible Accounts	1,545	1.595%	2.375%	2.275%	1,644
153	(905) Miscellaneous Customer Accounts Expenses	17	1.595%	2.375%	2.275%	18
154	TOTAL Customer Accounts Expenses	6,209				6,605
155						
156	(6) CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
157	Operation:					
158	(907) Supervision	2	1.595%	2.375%	2.275%	2
159	(908) Customer Assistance Expenses	73	1.595%	2.375%	2.275%	78
160	(909) Informational and Instructional Expenses	86	1.595%	2.375%	2.275%	92
161	(910) Miscellaneous Customer Service and Informational Expenses	-	1.595%	2.375%	2.275%	-
162	TOTAL Cust. Service and Informational Expenses	161				171
163						
164	(7) SALES EXPENSES					
165	Operation:					
166	(911) Supervision	-	1.595%	2.375%	2.275%	-
167	(912) Demonstrating and Selling Expenses	-	1.595%	2.375%	2.275%	-
168	(913) Advertising Expenses	2	1.595%	2.375%	2.275%	2
169	(916) Miscellaneous Sales Expenses	-	1.595%	2.375%	2.275%	-
170	TOTAL Sales Expenses	2				2
171						

Michigan Gas Utilities Corporation
Operation and Maintenance Expenses - Gas Utility
Historical and Forecasted - Non Labor

Line No.		2019	2020	2021	2022	2022 Forecasted
		Historical Total Non-Labor O&M	CPI	CPI		Total Non-Labor O&M Not Including K&M
172	(8) ADMINISTRATIVE AND GENERAL EXPENSES					
173	Operation:					
174	(920) Administrative and General Salaries	12	1.595%	2.375%	2.275%	13
175	(921) Office Supplies and Expenses	903	1.595%	2.375%	2.275%	960
176	(922) Administrative Expenses Transferred-Credit	-	1.595%	2.375%	2.275%	-
177	(923) Outside Services Employed	354	1.595%	2.375%	2.275%	376
178	(924) Property Insurance	34	1.595%	2.375%	2.275%	37
179	(925) Injuries and Damages	488	1.595%	2.375%	2.275%	520
180	(926) Employee Pensions and Benefits	4,312	1.595%	2.375%	2.275%	4,586
181	(927) Franchise Requirements	-	1.595%	2.375%	2.275%	-
182	(928) Regulatory Commission Expenses	375	1.595%	2.375%	2.275%	399
183	(929) Duplicate Charges-Cr.	-	1.595%	2.375%	2.275%	-
184	(930) Advertising Expenses	-	1.595%	2.375%	2.275%	-
185	(930.1) General Advertising Expenses	-	1.595%	2.375%	2.275%	-
186	(930.2) Miscellaneous General Expenses	1,057	1.595%	2.375%	2.275%	1,124
187	(931) Rents	439	1.595%	2.375%	2.275%	467
188	TOTAL Operation	7,973				8,481
189						
190	Maintenance:					
191	(935) Maintenance of General Plant	-	1.595%	2.375%	2.275%	-
192	TOTAL Maintenance	-				-
193	TOTAL Administrative and General Expenses	7,973				8,481
194						
195	TOTAL Operation and Maintenance Expenses	18,046				19,196

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 735
Manufactured Gas Plant Remediation

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Line

1	2022 Manufactured Gas Plant Remediation Amortization		\$	981,440
				<u>Non Labor</u>
2	2019 Manufactured Gas Plant Remediation Amortization		\$	887,703
3	2020 Inflation	1.595%		
4	2021 Inflation	2.375%		
5	2022 Inflation	2.275%		
6	Composite Inflation	6.374%		
7	Inflation on 2019 Manufactured Gas Plant Remediation Amortization		\$	56,583
8	2019 Manufactured Gas Plant Remediation Amortization Inflated to 2022		\$	944,286
9	Known and Measurable Increase (Decrease) in 2022		\$	37,154

Account 735

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Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 816
Underground Storage Expenses - Wells

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Line

1	2022 FERC (816) Wells			\$	109,642
2	2019 FERC (816) Wells		<u>Labor</u>	<u>Non Labor</u>	
		\$	31,037	\$	43,200
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 FERC (816) Wells		\$	2,651	\$ 2,754
8	2019 FERC (816) Wells Inflated to 2022				\$ 79,642
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 30,000</u>

Account 816

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 824
Underground Storage Expenses - Other

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Line

1	2022 FERC (824) Other Expenses			\$	222,175
2	2019 FERC (824) Other Expenses		<u>Labor</u>	<u>Non Labor</u>	
		\$	64,410	\$	96,136
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (824) Other Expenses		\$	5,501	\$ 6,128
8	2019 (824) Other Expenses Inflated to 2022				\$ 172,175
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 50,000</u>

Account 824

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 856
Transmission Operations Mains Expense

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Line

1	2022 FERC (856) Mains Exp			\$	206,294
2	2019 FERC (856) Mains Exp		<u>Labor</u>		<u>Non Labor</u>
		\$	16,407	\$	12,677
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (856) Mains Exp		\$	1,401	\$ 808
8	2019 (856) Mains Exp Inflated to 2022				\$ 31,294
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 175,000</u>

Account 856

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 859
Transmission Operations Other Expenses

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Line

1	2022 FERC (859) Other Expenses			\$	73,938
2	2019 FERC (859) Other Expenses		<u>Labor</u>	<u>Non Labor</u>	
		\$	1,235	\$	49,446
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (859) Other Expenses		\$	105	\$ 3,152
8	2019 (859) Other Expenses Inflated to 2022				\$ 53,938
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 20,000</u>

Account 859

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 863
Transmission Maintenance of Mains

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Line

1	2022 FERC (863) Maintenance of Mains			\$	85,245
2	2019 FERC (863) Maintenance of Mains		<u>Labor</u>	<u>Non Labor</u>	
		\$	28,036	\$	4,526
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (863) Maintenance of Mains		\$	2,395	\$ 288
8	2019 (863) Maintenance of Mains Inflated to 2022				\$ 35,245
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 50,000</u>

Account 863

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 874
Distribution Operations Mains and Services Expenses

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Line

1	2022 FERC (874) Mains and Services Expenses			\$ 2,343,509
		<u>Labor</u>	<u>Non Labor</u>	
2	2019 FERC (874) Mains and Services Expenses	\$ 1,470,377	\$ 407,564	
3	2020 Inflation	2.530%	1.595%	
4	2021 Inflation	2.800%	2.375%	
5	2022 Inflation	2.980%	2.275%	
6	Composite Inflation	8.541%	6.374%	
7	Inflation on 2019 (874) Mains and Services Expenses	\$ 125,590	\$ 25,978	
8	2019 (874) Mains and Services Expenses Inflated to 2022			\$ 2,029,509
9	Known and Measurable Increase (Decrease) in 2022			<u>\$ 314,000</u>

Account 874

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 880
Distribution Operations Other Expenses

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Line

1	2022 FERC (880) Other Expenses			\$ 2,665,885
		<u>Labor</u>	<u>Non Labor</u>	
2	2019 FERC (880) Other Expenses	\$ 1,433,992	\$ 819,902	
3	2020 Inflation	2.530%	1.595%	
4	2021 Inflation	2.800%	2.375%	
5	2022 Inflation	2.980%	2.275%	
6	Composite Inflation	8.541%	6.374%	
7	Inflation on 2019 (880) Other Expenses	\$ 122,482	\$ 52,261	
8	2019 (880) Other Expenses Inflated to 2022			\$ 2,428,637
9	Known and Measurable Increase (Decrease) in 2022			<u>\$ 237,248</u>

Account 880

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 887
Distribution Maintenance of Mains

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Line

1	2022 FERC (887) Maintenance of Mains			\$	727,174
2	2019 FERC (887) Maintenance of Mains		<u>Labor</u>	<u>Non Labor</u>	
		\$	434,289	\$	146,456
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (887) Maintenance of Mains		\$	37,094	\$ 9,335
8	2019 (887) Maintenance of Mains Inflated to 2022				\$ 627,174
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 100,000</u>

Account 887

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 889
Distribution Maintenance of Measuring and Regulating Station Equipment - General

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Line

1	2022 FERC (889) Measuring and Regulating Station Equipment - General			\$	538,698
			<u>Labor</u>		<u>Non Labor</u>
2	2019 FERC (889) Measuring and Regulating Station Equipment - General	\$	60,419	\$	21,734
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (889) Measuring and Regulating Station Equipment - General	\$	5,161	\$	1,385
8	2019 (889) Measuring and Regulating Station Equipment - General Inflated to 2022			\$	88,698
9	Known and Measurable Increase (Decrease) in 2022			\$	450,000
					Account 889

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 892
Distribution Maintenance of Services

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Line

1	2022 FERC (892) Maintenance of Services			\$	906,228
2	2019 FERC (892) Maintenance of Services		<u>Labor</u>	<u>Non Labor</u>	
		\$	119,378	\$	90,861
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (892) Maintenance of Services		\$	10,196	\$ 5,792
8	2019 (892) Maintenance of Services Inflated to 2022				\$ 226,228
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 680,000</u>

Account 892

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 893
Distribution Maintenance of Meters and House Regulators

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Line

1	2022 FERC (893) Maintenance of Meters & House Regulators			\$	566,112
2	2019 FERC (893) Maintenance of Meters & House Regulators		<u>Labor</u>	<u>Non Labor</u>	
		\$	222,264	\$	62,857
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (893) Maintenance of Meters & House Regulators		\$	18,984	\$ 4,007
8	2019 (893) Maintenance of Meters & House Regulators Inflated to 2022				\$ 308,112
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ 258,000</u>

Account 893

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 902
Customer Accounts Expense - Meter Reading

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Line

1	2022 FERC (902) Meter Reading Expenses			\$	605,558
			<u>Labor</u>		<u>Non Labor</u>
2	2019 FERC (902) Meter Reading Expenses		\$ 1,128,038	\$	816,177
3	2020 Inflation	2.530%		1.595%	
4	2021 Inflation	2.800%		2.375%	
5	2022 Inflation	2.980%		2.275%	
6	Composite Inflation	8.541%		6.374%	
7	Inflation on 2019 (902) Meter Reading Expenses		\$ 96,350	\$	52,024
8	2019 (902) Meter Reading Expenses Inflated to 2022			\$	2,092,588
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ (1,487,030)</u>
					Account 902

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 903
Customer Accounts Expenses - Customer Records and Collection

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Line

1	2022 FERC (903) Customer Records and Collection Expenses			\$ 5,169,445
			<u>Labor</u>	<u>Non Labor</u>
2	2019 FERC (903) Customer Records and Collection Expenses	\$	991,158	\$ 3,829,532
3	2020 Inflation	2.530%		1.595%
4	2021 Inflation	2.800%		2.375%
5	2022 Inflation	2.980%		2.275%
6	Composite Inflation	8.541%		6.374%
7	Inflation on 2019 (903) Customer Records and Collection Expenses	\$	84,658	\$ 244,097
8	2019 (903) Customer Records and Collection Expenses Inflated to 2022			\$ 5,149,445
9	Known and Measurable Increase (Decrease) in 2022			<u>\$ 20,000</u>

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 904
Customer Accounts Expenses - Uncollectible Accounts

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Line

1	2022 Uncollectible Accounts	\$ 1,911,595

2	2019 Uncollectible Accounts	<u>Non Labor</u> \$ 1,545,297

3	2020 Inflation	1.595%

4	2021 Inflation	2.375%

5	2022 Inflation	2.275%

6	Composite Inflation	6.374%

7	Inflation on 2019 Uncollectible Accounts	\$ 98,498

8	2019 Uncollectible Accounts Inflated to 2022	\$ 1,643,795

9	Known and Measurable Increase (Decrease) in 2022	\$ 267,800

Account 904

<u>Line</u>	<u>Year</u>	<u>Write-Offs</u>	<u>Collections</u>	<u>Net</u> <u>Uncollectibles</u>	<u>Total</u> <u>Gas Service</u> <u>Revenues</u>	<u>Net Uncollectibles</u> <u>as a Percent of</u> <u>Revenue</u>
		[P-522, Page 228A]			[P-522, Page 300 less EWR]	
1	2015	\$1,575,127	\$0	\$1,575,127	\$131,705,632	1.1959%
2	2016	\$1,449,782	\$0	\$1,449,782	\$123,210,882	1.1767%
3	2017	\$1,418,907	\$0	\$1,418,907	\$133,619,877	1.0619%
4	2018	\$2,411,987	\$0	\$2,411,987	\$145,314,914	1.6598%
5	2019	\$2,321,422	\$0	\$2,321,422	\$137,937,019	1.6830%
6					Average	<u>1.3555%</u>
7						
8						
9	<u>Allowance for Uncollectible Expense for 2022</u>					
10						
11		2022 Forecasted Total Revenue without rate increase			\$141,029,176	
12		5-Year Average Net Uncollectibles as a Percent of Revenue			<u>1.35546%</u>	
13		Net Uncollectibles Allowance for 2022			\$1,911,595	
14						

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 925
Administrative and General - Injuries and Damages Expenses

Case No.: U-20718
Exhibit No.: A-17
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Line

1	2022 Injuries & Damages, 5 year average		\$	586,042
		<u>Non Labor</u>		
2	2019 Injuries & Damages		\$	488,410.0
3	2020 Inflation	1.595%		
4	2021 Inflation	2.375%		
5	2022 Inflation	2.275%		
6	Composite Inflation	6.374%		
7	Inflation on 2019 Costs		\$	31,131.5
8	2019 Costs Inflated to 2022		\$	519,542
9	Known and Measurable Increase (Decrease) in 2022		\$	66,501

Account 925

Year

Actual

MICHIGAN GAS UTILITY COMPANY
Known and Measurable Adjustment, account 926
Administrative and General - Employee Pensions and Benefits Expenses
Summary of Employee Benefit Costs
Test Year Ended December 31, 2022

Case No.: U-20718
Exhibit No.: A-17
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		2019 Actual \$	2022 Forecast \$	Increase \$	Increase %	Forecast Method
Line No.	Description					
1	Medical Benefits	\$ 1,601,213	\$ 1,937,216	\$ 336,003	21.0%	MGUC Estimate
2	Dental Benefits	\$ 78,544	\$ 84,004	\$ 5,460	7.0%	MGUC Estimate
3	401(k)	\$ 1,023,240	\$ 1,103,036	\$ 79,796	7.8%	MGUC Estimate
4	Subtotal - MGUC Estimate	\$ 2,702,997	\$ 3,124,256	\$ 421,259	15.6%	
5	Long Term Disability	\$ 51,996	\$ 55,310	\$ 3,314	6.4%	Inflationary
6	Life Insurance	\$ 21,060	\$ 22,402	\$ 1,342	6.4%	Inflationary
7	Tuition Reimbursement and Other	\$ 9,059	\$ 9,636	\$ 577	6.4%	Inflationary
8	Executive Benefits	\$ 94,385	\$ 100,401	\$ 6,016	6.4%	Inflationary
9	Benefit Administration	\$ 34,923	\$ 37,149	\$ 2,226	6.4%	Inflationary
10	Benefits Billed from Affiliates	\$ 73,943	\$ 78,656	\$ 4,713	6.4%	Inflationary
11	Capitalized Benefits	\$ (1,474,787)	\$ (1,568,791)	\$ (94,004)	6.4%	Inflationary
12	Subtotal - Inflationary Items	\$ (1,189,421)	\$ (1,265,237)	\$ (75,816)	6.4%	
13	Qualified Pension	\$ 513,662	\$ 1,144,035	\$ 630,373	122.7%	Actuarial Analysis
14	NonQualified Pension	\$ 28,205	\$ 25,464	\$ (2,741)	-9.7%	Actuarial Analysis
15	OPEB	\$ 355,657	\$ 73,709	\$ (281,948)	-79.3%	Actuarial Analysis
16	Postemployment	\$ 104,580	\$ -	\$ (104,580)	-100.0%	Actuarial Analysis
17	Subtotal - Actuarial Analysis	\$ 1,002,104	\$ 1,243,208	\$ 241,104	24.1%	
18	Benefits Billed from WBS	\$ 1,795,894	\$ 2,017,402	\$ 221,508	12.3%	See Page 2
19	TOTAL EMPLOYEE BENEFIT COSTS	\$ 4,311,574	\$ 5,119,629	\$ 808,055	18.7%	
20	Composite non-labor inflation rate	6.374%				
21	2019 Costs inflated to 2022	\$ 4,586,396				
22	Known and Measurable Increase (Decrease) in 2022	\$ 533,233				
	Non Labor Inflation Rates					
	2020	1.595%		1.01595		
	2021	2.375%		1.02375		
	2022	2.275%		1.02275		
	Labor Inflation Rates					
	2020	2.53%		1.0253		
	2021	2.80%		1.0280		
	2022	2.98%		1.0298		

MICHIGAN GAS UTILITY COMPANY
Known and Measurable Adjustment, account 926
Summary of Employee Benefit Costs

Test Year Ended December 31, 2022

Case No.: U-20718
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Page: 2 of 2
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Line No.	Description	2019 Actual \$	2022 Forecast \$	Increase \$	Increase %	Forecast Method
1	Medical Benefits	\$ 14,845,958	\$ 17,804,444	\$ 2,958,486	19.9%	MGUC Estimate
2	Dental Benefits	\$ 735,154	\$ 779,393	\$ 44,239	6.0%	MGUC Estimate
3	401(k)	\$ 13,567,981	\$ 14,498,351	\$ 930,370	6.9%	MGUC Estimate
4	Subtotal - MGUC Estimate	\$ 29,149,093	\$ 33,082,188	\$ 3,933,095	13.5%	
5	Long Term Disability	\$ 507,597	\$ 539,952	\$ 32,355	6.4%	Inflationary
6	Life Insurance	\$ 284,476	\$ 302,609	\$ 18,133	6.4%	Inflationary
7	Tuition Reimbursement and Other	\$ 295,789	\$ 314,643	\$ 18,854	6.4%	Inflationary
8	Executive Benefits	\$ 55,177,158	\$ 58,694,183	\$ 3,517,025	6.4%	Inflationary
9	Benefit Administration	\$ 329,502	\$ 350,505	\$ 21,003	6.4%	Inflationary
10	Benefits Billed from Affiliates	\$ 2,402	\$ 2,555	\$ 153	6.4%	Inflationary
11	Subtotal - Inflationary Items	\$ 56,596,924	\$ 60,204,447	\$ 3,607,523	6.4%	
12	Qualified Pension	\$ (5,834,782)	\$ (4,707,099)	\$ 1,127,683	-19.3%	Actuarial Analysis
13	NonQualified Pension	\$ 9,270,246	\$ 12,662,337	\$ 3,392,091	36.6%	Actuarial Analysis
14	OPEB	\$ 324,693	\$ (371,751)	\$ (696,444)	-214.5%	Actuarial Analysis
15	Postemployment	\$ 448,095	\$ -	\$ (448,095)	-100.0%	Actuarial Analysis
16	Subtotal - Actuarial Analysis	\$ 4,208,252	\$ 7,583,487	\$ 3,375,235	80.2%	
17	TOTAL EMPLOYEE BENEFIT COSTS	\$ 89,954,269	\$ 100,870,122	\$ 10,915,853	12.1%	
18	Allocation Percentage from WBS to MGUC	2.0%	2.0%			
19	Allocation Dollars from WBS to MGUC	\$ 1,795,894	\$ 2,017,402	\$ 221,508	12.3%	

Non Labor Inflation Rates

2020	1.595%	1.01595
2021	2.375%	1.02375
2022	2.275%	1.02275

Labor Inflation Rates

2020	2.53%	1.0253
2021	2.80%	1.0280
2022	2.98%	1.0298

Michigan Gas Utilities Corporation
Known and Measurable Adjustment, account 930.2
Administrative and General - Miscellaneous General Expenses

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Line

1	2022 FERC (930.2) Miscellaneous General Expenses				\$ 1,136,715
		<u>Labor</u>	<u>Non Labor*</u>	<u>Service Company</u> <u>(WBS) Return</u> <u>on/off</u>	
2	2019 FERC (930.2) Miscellaneous General Expenses	\$ 36,014	\$ 643,742	\$ 412,844	
3	2020 Inflation	2.530%	1.595%	1.595%	
4	2021 Inflation	2.800%	2.375%	2.375%	
5	2022 Inflation	2.980%	2.275%	2.275%	
6	Composite Inflation	8.541%	6.374%	6.374%	
7	Inflation on 2019 (930.2) Miscellaneous General Expenses	\$ 3,076	\$ 41,032	\$ 26,315	
8	2019 (930.2) Miscellaneous General Expenses Inflated to 2022				\$ 1,163,023
9	Known and Measurable Increase (Decrease) in 2022				<u>\$ (26,309)</u>
10	*Service Company Return on/off is in Non Labor but separated here for clarity				Account 930.2

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Exhibit No.: A-17
Schedule: C19
Page: 2 of 2
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[illegible]

Michigan Gas Utilities Corporation
Estimate of Inflation for 2020, 2021, and 2022

<u>Line</u>	<u>Source</u>	<u>Date</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>
1	Value Line	August 28, 2020	0.600%	2.100%	1.800%
2	EIA	October, 2020*	2.590%	2.650%	2.750%
3	MGUC Estimate (Simple Average)		1.595%	2.375%	2.275%
4	Cumulative Impact from 2019 to 2021			4.01%	6.37%

* 2022 data from EIA Annual Outlook	October, 2020	2.750%

January, 2020

WEC ENERGY GROUP ANNUAL INCENTIVE PAY PLAN FOR NON-EXECUTIVES

PURPOSE

The purpose of the Annual Incentive Pay Plan for Non-Executives ("Plan") is to promote the achievement of WEC Energy Group objectives driving cost control, safety, customer satisfaction and diversity among others, while recognizing individual performance. To foster achievement of these objectives, a portion of annual compensation for certain employees is considered "at risk". The Plan is an annual incentive plan for all eligible employees in which award funding is based on achievement of actual performance in relation to predetermined performance goals.

ELIGIBILITY

All WEC Energy Group regular full-time and part-time management and administrative employees, excluding participants in any other type of annual variable incentive program, or employees covered under a collective bargaining agreement, are eligible for participation under the Plan. New hires, employees promoted into eligible positions, or other mid-year transfers are eligible for the Plan, provided their status as an eligible employee commenced prior to Nov. 1 of the Plan Year. Awards for part-year participants may be pro-rated to reflect their time in the Plan.

PLAN YEAR

For purposes of the Plan, the "Plan Year" is the calendar year.

PLAN CATEGORIES

Under the Plan, eligible participants are classified as either a **Group A or Group B** participant. There are different administrative and governance provisions for certain aspects of the Plan for participants in each group. An employee may move from Group A to Group B, or vice versa, during the plan year. Administration for these employees is handled under the respective process (defined below) for each group, pro-rated based on the time in each group.

TARGET AWARD LEVELS

For each position eligible for Plan participation, a variable incentive award target is set based on market compensation trends. An individual employee's target is expressed as a percent of his/her base salary.

Group A participants cover the preponderance of jobs and carry a target of 5 or 10 percent. Participants in **Group B** have a 15 percent incentive target or higher. Employee nominations to Group B are subject to approval of the WEC Energy Group chief executive officer (CEO).

COVERED COMPENSATION

Incentive awards are based on an employee's annual base salary at the time of the annual salary plan (Nov. 1, or another date established by the Compensation department). Covered compensation for Group B participants is subject to adjustment due to mid-year salary or incentive target changes as described in "Determining Awards" section below. Pay for spot bonuses, including bonuses recognizing additional work hours for exempt employees, disability payments, or any other form of additional payment is not included in the incentive calculation. Calculated awards are adjusted to account for overtime worked by nonexempt employees as required by law.

PERFORMANCE MEASURES

Prior to the beginning of each plan year, the CEO will establish applicable goals for each covered entity which are supportive of corporate objectives. Minimum, expected and maximum performance levels will be specified for each goal. Goals will be communicated as soon as practical after they have been established.

The goals will not normally be modified, once established for the plan year, unless unforeseen circumstances occur which would have substantially influenced the setting of the goals had such circumstances been known at the time. Any change is subject to approval of the CEO.

DETERMINING AWARDS (Group A)

Awards under the Plan are determined as follows for Group A participants:

1. **Creating the award pool:** Individual award target percentages are multiplied by each participant's base salary, yielding an individual "at plan" award. The "at plan" award is based on an assumption that expected performance is achieved for each objective. The total of all "at plan" awards for employees in the department makes up the award pool for that department. The award pool is based on aggregate targets effective at the time of the annual salary plan (Nov. 1, or another date established by the company's Compensation department).
2. **Individual adjustments:** Individual "at plan" awards may be adjusted up or down based on individual performance as reflected in the employee's annual performance plan and applying guidelines established by the company. Employees deemed to have unsatisfactory performance may receive a reduced Plan award or no award at all. Funding for such individuals may be distributed among the remaining participants in the department. Employees who exceed expectations may receive an award higher than "at plan" subject to available funding. The aggregate of all awards in the department must not exceed the department's pool.
3. **Partial year participation:** At the discretion of the officer in charge of the department, awards will be available to new hires, transferees, or employees who become eligible through promotion. The approval will take into account such factors as the individual's overall contribution and the portion of the year the individual spent with the company and may be adjusted to reflect time actually participating.
4. **No transfer of pool funds:** Funding from the pool of awards from Group A participants may not be applied to participants in Group B, and vice versa. Award pool funding may not be transferred between departments without the approval of the most senior executive in charge of each department, and the CEO.
5. **Final awards:** Following year-end business results, final awards are determined by applying a factor resulting from attainment of the covered entity's pre-determined performance measures. The performance factor applied to an employee's award is based on the plan measures the employee was covered under at the time of the annual salary plan. Performance factors are not pro-rated or averaged in the event of a mid-year transfer between entities with differing measures.
6. **Approvals:** All final awards are subject to CEO review and approval.

DETERMINING AWARDS (Group B)

Awards under the Plan are determined as follows for Group B participants:

1. **Individual targets:** Individual award target percentages are multiplied by each participant's base salary yielding an individual "at plan" award. The "at plan" award is based on an assumption that expected performance is achieved for each objective. This individual target reflects any compensation adjustments (base salary or target incentive) resulting from a mid-year hire, transfer, promotion, retirement, etc.

2. **Individual performance adjustments:** Individual “at plan” awards may be adjusted up or down based on individual performance as reflected in the employee’s annual performance plan and applying guidelines established by the company, by means of an Individual Performance Adjustment (“IPA”) factor. Employees deemed to have unsatisfactory performance may receive a reduced Plan award or no award at all. Employees who achieve or exceed performance expectations should receive no IPA. Consideration for an IPA over 1.00 is extremely rare and subject to the approval of the CEO.
3. **Partial year participation:** Awards will be available to new hires, transferees or employees who become eligible through promotion adjusted to reflect time as a participant.
4. **No transfer of funds:** The application of an IPA is not considered a pooling mechanism to create funding dollars to allocate among other participants. Downward IPAs may not be used to create incentive dollars to apply to Group A participants, other Group B participants, or participants in another department.
5. **Final Awards:** Following year-end business results, final awards are determined by applying a factor resulting from attainment of the covered entity’s pre-determined performance measures. The performance factor applied to an employee’s award is based on the plan measures the employee was covered under during the plan year. Performance factors are pro-rated in the event of a mid-year transfer between entities with differing measures.
6. **Approvals:** All final awards are subject to CEO review and approval.

FORM AND TIMING OF PAYMENT

Incentive awards shall be paid as soon as practical after award amounts are approved by the CEO following year-end, but no later than March 15 following the plan year in which the award was earned. All awards are paid in cash.

TERMINATION / PLAN INELIGIBILITY

Participating employees terminated due to job elimination or organizational changes, and are thereby eligible for severance benefits, or who leave service and are at least 55 years old and have at least 10 years of service, or otherwise leave service and are eligible under a “rule of 85” plan benefit, or who terminate their employment during the year due to disability or death remain eligible for a prorated award for that year. Terminated employees who receive severance benefits are eligible for a prorated Plan award for the year in which they were terminated (performance warranting) *unless* payment in lieu of a Plan award is provided in the severance agreement, *or* Plan payment is expressly excluded from the severance agreement.

Employees who terminate their employment during the Plan Year for any other reason than as described above, including voluntary termination or termination for cause, OR who transfer to a non-eligible position during the year are not eligible for any portion of a Plan award paid in the subsequent year.

TAX TREATMENT

Cash payments are taxable to the participant in the year of receipt. The company will have the right to deduct any federal, state or local taxes required by law to be withheld.

BENEFICIARY DESIGNATION

The beneficiary elected for basic life coverage shall be the same beneficiary to whom any benefit under this Plan is to be paid in the case of death.

EFFECT ON EMPLOYEE BENEFIT PLANS

The treatment of awards paid under the Plan for purposes of the company’s welfare and retirement plans will be determined under the terms of the respective welfare and retirement plans under which the eligible employee is covered.

PARTICIPANT RIGHTS

Participation in the Plan is not a guarantee of employment. Rights or interests to an award are not transferable.

ADMINISTRATION

The WEC Energy Group officer directly in charge of Human Resources is charged with the administration of the Plan.

AMENDMENTS

The CEO has sole discretionary rights to interpret, modify, amend, suspend or terminate, in whole or in part, any or all of the provisions of the Plan

Michigan Gas Utilities (MGU)						
Weighting by measurement			Funding	Goals	Example	
Cost control	MGU net income	Threshold Intermediate Target Maximum	MGU Incentive Plan calculation example	Annual base salary: Target incentive award: of annual base salary 		

2021 Annual Incentive Plan Overview

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WEC Business Services* (WBS)								
Weighting by measurement			Funding	Goals	Example			
Cost control	controllable O&M across WEC Energy Group		Threshold		WBS Incentive Plan calculation example	Funds	at threshold:	
			Intermediate			Funds	at intermediate:	
			Target			Funds	at target:	
			Maximum			Funds	at maximum:	
Customer satisfaction	total company aggregated transaction satisfaction	Weighted based on average customer population: Ve Energies PGL WPS MERC MGU NSG	Threshold		Annual base salary: Target incentive award: of annual base salary	Funds	at threshold:	
			Target			Funds	at target:	
			Maximum			Funds	at maximum:	
	total company aggregated satisfaction		Threshold			Funds	at threshold:	
			Target			Funds	at target:	
			Maximum			Funds	at maximum:	
Safety	WBS OSHA-recordable injuries		Threshold		Actual individual target incentive awards may vary, depending on position. Performance below threshold levels will yield no funding.	Funds	at threshold:	
			Target			Funds	at target:	
			Maximum			Funds	at maximum:	
	WBS lost-time injuries		Threshold			Funds	at threshold:	
			Target			Funds	at target:	
			Maximum			Funds	at maximum:	
Diversity	total company supplier diversity		Total combined company goals			Funds	at threshold:	
			Threshold			Funds	at target:	
			Target			Funds	at maximum:	
			Maximum					
	total company workforce diversity		WEC Energy Group workforce diversity goals, as determined by WEC chief executive officer.			Funds	at threshold:	
						Funds	at target:	
						Funds	at maximum:	

O&M: Operations and maintenance OSHA: Occupational Safety and Health Administration

* WBS employees in the Illinois Operations business unit – Illinois Corporate Communications and Illinois Operations divisions only - are measured on combined results of Peoples Gas and North Shore Gas.

Line No	Description	Source	2023	2024	2025	2026	2027
			(a)	(b)	(c)	(d)	(e)
Capital Investment							
1	Annual MRP Investment	Witness Lee Testimony	3,000,000	8,891,667	8,891,667	8,891,666	2,025,000
Net Rate Base							
2	Cumulative Capital Investment	Prior Year Plus Line 1	3,000,000	11,891,667	20,783,334	29,675,000	31,700,000
3	Accumulated Depreciation	Prior Year - Line 8	(43,800)	(261,218)	(738,273)	(1,474,965)	(2,371,040)
4	Accumulated Deferred Taxes	Page 2; Line 5	(68,700)	(332,589)	(698,582)	(1,017,642)	(1,136,077)
5	Ending Net Rate Base	Sum Line 2 - Line 4	2,887,500	11,297,859	19,346,479	27,182,393	28,192,883
6	Average Net Rate Base	Line 5 (PY + CY)/2	1,443,750	5,648,930	9,673,239	13,591,197	14,096,442
Total Cost							
7	Return on Rate Base	8.68%	125,318	490,327	839,637	1,179,716	1,223,571
8	Depreciation (1/2 year convention)	2.92%	43,800	217,418	477,055	736,692	896,075
9	Property Taxes	Page 2	-	69,750	271,981	460,875	637,181
11	Total Revenue Requirement	Line 7 Thru Line 10	<u>169,118</u>	<u>777,495</u>	<u>1,588,673</u>	<u>2,377,283</u>	<u>2,756,827</u>

Line No	Description	Source	2023 (a)	2024 (b)	2025 (c)	2026 (d)	2027 (e)
Deferred Tax Expense							
1	Tax Depreciation	Line 7	112,500	550,008	1,175,637	1,754,334	2,032,152
2	Book Depreciation	Page 1 Line 8	43,800	217,418	477,055	736,692	896,075
3	Time Difference	Line 2 - Line 1	68,700	332,589	698,582	1,017,642	1,136,077
4	Deferred Tax Expense	25.7%	17,683	85,608	179,815	261,941	292,426
5	Accumulated Deferred Tax Expense	Prior Year Plus Line 4	17,683	103,292	283,107	545,048	837,474
Tax Depreciation							
6	MACRS Tax Depreciation Rate (20 Years)		Year 1 3.750%	Year 2 7.219%	Year 3 6.677%	Year 4 6.177%	Year 5 5.713%
7	Year 1 Additions	Cost & MACRS Rate	112,500	216,570	200,310	185,310	171,390
8	Year 2 Additions	Cost & MACRS Rate		333,438	641,889	593,697	549,238
9	Year 3 Additions	Cost & MACRS Rate			333,438	641,889	593,697
10	Year 4 Additions	Cost & MACRS Rate				333,437	641,889
11	Year 5 Additions	Cost & MACRS Rate					75,938
12	Total Tax Depreciation	Sum of Lines 7 thru 11	112,500	550,008	1,175,637	1,754,334	2,032,152
Property Tax							
13	Factor		0.93	0.87	0.81	0.76	0.71
14	Year 1 Investment Taxable Value	Cost X Factor X 50%	1,395,000	1,305,000	1,215,000	1,140,000	1,065,000
15	Year 2 Investment Taxable Value	Cost X Factor X 50%		4,134,625	3,867,875	3,601,125	3,378,833
16	Year 3 Investment Taxable Value	Cost X Factor X 50%			4,134,625	3,867,875	3,601,125
17	Year 4 Investment Taxable Value	Cost X Factor X 50%				4,134,625	3,867,875
18	Year 5 Investment Taxable Value	Cost X Factor X 50%					941,625
19	Total Taxable Value	Sum of Lines 13 thru 17	1,395,000	5,439,625	9,217,500	12,743,625	12,854,458
20	Millage	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50	\$ 50
21	Property Tax Assessed	(Line 19 X Line 20) / 1000	69,750	271,981	460,875	637,181	642,723
22	Property Tax Expense			69,750	271,981	460,875	637,181

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	General Service- Residential	Customer Choice- Residential	Agg Transport- Residential	General Service Small	Customer Choice-GS- Small	Agg Transport- GS-Small	Transport-TR-1	General Service Large	Transport-TR-2	Customer Choice-GS- Large	Agg Transport- GS-Large	Transport-TR-3	Special Contract
1	2022 dist. main plant in service (Workpaper ALN-2)	196,127,120	124,495,061	17,818,796	11,944	22,529,343	5,321,700	1,588,420	4,977,428	1,814,106	11,621,281	70,016	76,249	5,345,382	457,395
2	2022 dist. main class allocation	1.000000	0.634767	0.090853	0.000061	0.114871	0.027134	0.008099	0.025379	0.009250	0.059254	0.000357	0.000389	0.027255	0.002332
3	MRP Revenue Requirement (Exhibit A-20)	\$169,118	\$107,350	\$15,365	\$10	\$19,427	\$4,589	\$1,370	\$4,292	\$1,564	\$10,021	\$60	\$66	\$4,609	\$394
4	2022 daily average customers (Exhibit A-16, Schedule F1.3)	182,332	146,650	21,110	7	11,364	2,737	252	109	54	40	3	2	3	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168	854,602	6,659,678	21,109	26,200	3,126,872	275
6	Average use per customer		81.5	79.9	402.1	468.9	456.9	2,158.6	20,047.4	15,835.0	166,492.0	7,036.4	12,058.6	1,042,290.7	274.8
7	Annual cost per customer		\$0.73	\$0.73	\$1.47	\$1.71	\$1.68	\$5.44	\$39.38	\$28.98	\$250.52	\$20.12	\$30.26	\$1,536.41	\$394.40
8	Monthly cost per customer		\$0.07	\$0.07	\$0.13	\$0.15	\$0.14	\$0.46	\$3.29	\$2.42	\$20.88	\$1.68	\$2.53	\$128.04	\$32.87

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	General Service Residential	Customer Choice-Residential	Agg Transport-Residential	General Service Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1	General Service Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2022 dist. main plant in service (Workpaper ALN-2)	196,127,120	124,495,061	17,818,796	11,944	22,529,343	5,321,700	1,588,420	4,977,428	1,814,106	11,621,281	70,016	76,249	5,345,382	457,395
2	2022 dist. main class allocation	1.000000	0.634767	0.090853	0.000061	0.114871	0.027134	0.008099	0.025379	0.009250	0.059254	0.000357	0.000389	0.027255	0.002332
3	MRP Revenue Requirement (Exhibit A-20)	\$777,495	\$493,529	\$70,638	\$47	\$89,312	\$21,097	\$6,297	\$19,732	\$7,192	\$46,070	\$278	\$302	\$21,190	\$1,813
4	2022 daily average customers (Exhibit A-16, Schedule F1.3)	182,332	146,650	21,110	7	11,364	2,737	252	109	54	40	3	2	3	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168	854,602	6,659,678	21,109	26,200	3,126,872	275
6	Average use per customer		81.5	79.9	402.1	468.9	456.9	2,158.6	20,047.4	15,835.0	166,492.0	7,036.4	12,058.6	1,042,290.7	274.8
7	Annual cost per customer		\$3.37	\$3.35	\$6.76	\$7.86	\$7.71	\$24.99	\$181.03	\$133.25	\$1,151.74	\$92.52	\$139.12	\$7,063.46	\$1,813.22
8	Monthly cost per customer		\$0.29	\$0.28	\$0.57	\$0.66	\$0.65	\$2.09	\$15.09	\$11.11	\$95.98	\$7.71	\$11.60	\$588.63	\$151.11

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	General Service Residential	Customer Choice-Residential	Agg Transport-Residential	General Service Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1	General Service Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2022 dist. main plant in service (Workpaper ALN-2)	196,127,120	124,495,061	17,818,796	11,944	22,529,343	5,321,700	1,588,420	4,977,428	1,814,106	11,621,281	70,016	76,249	5,345,382	457,395
2	2022 dist. main class allocation	1.000000	0.634767	0.090853	0.000061	0.114871	0.027134	0.008099	0.025379	0.009250	0.059254	0.000357	0.000389	0.027255	0.002332
3	MRP Revenue Requirement (Exhibit A-20)	\$1,588,673	\$1,008,438	\$144,336	\$97	\$182,493	\$43,107	\$12,867	\$40,318	\$14,695	\$94,135	\$567	\$618	\$43,299	\$3,705
4	2022 daily average customers (Exhibit A-16, Schedule F1.3)	182,332	146,650	21,110	7	11,364	2,737	252	109	54	40	3	2	3	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168	854,602	6,659,678	21,109	26,200	3,126,872	275
6	Average use per customer		81.5	79.9	402.1	468.9	456.9	2,158.6	20,047.4	15,835.0	166,492.0	7,036.4	12,058.6	1,042,290.7	274.8
7	Annual cost per customer		\$6.88	\$6.84	\$13.82	\$16.06	\$15.75	\$51.06	\$369.89	\$272.28	\$2,353.37	\$189.05	\$284.26	\$14,432.93	\$3,705.00
8	Monthly cost per customer		\$0.58	\$0.57	\$1.16	\$1.34	\$1.32	\$4.26	\$30.83	\$22.69	\$196.12	\$15.76	\$23.69	\$1,202.75	\$308.75

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	General Service Residential	Customer Choice-Residential	Agg Transport-Residential	General Service Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1	General Service Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2022 dist. main plant in service (Workpaper ALN-2)	196,127,120	124,495,061	17,818,796	11,944	22,529,343	5,321,700	1,588,420	4,977,428	1,814,106	11,621,281	70,016	76,249	5,345,382	457,395
2	2022 dist. main class allocation	1.000000	0.634767	0.090853	0.000061	0.114871	0.027134	0.008099	0.025379	0.009250	0.059254	0.000357	0.000389	0.027255	0.002332
3	MRP Revenue Requirement (Exhibit A-20)	\$2,377,283	\$1,509,021	\$215,984	\$145	\$273,081	\$64,505	\$19,253	\$60,332	\$21,989	\$140,863	\$849	\$924	\$64,792	\$5,544
4	2022 daily average customers (Exhibit A-16, Schedule F1.3)	182,332	146,650	21,110	7	11,364	2,737	252	109	54	40	3	2	3	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168	854,602	6,659,678	21,109	26,200	3,126,872	275
6	Average use per customer		81.5	79.9	402.1	468.9	456.9	2,158.6	20,047.4	15,835.0	166,492.0	7,036.4	12,058.6	1,042,290.7	274.8
7	Annual cost per customer		\$10.29	\$10.23	\$20.68	\$24.03	\$23.57	\$76.40	\$553.51	\$407.44	\$3,521.58	\$282.89	\$425.37	\$21,597.36	\$5,544.14
8	Monthly cost per customer		\$0.86	\$0.86	\$1.73	\$2.01	\$1.97	\$6.37	\$46.13	\$33.96	\$293.47	\$23.58	\$35.45	\$1,799.78	\$462.02

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Line Description	Total MGU Natural Gas	General Service Residential	Customer Choice-Residential	Agg Transport-Residential	General Service Small	Customer Choice-GS-Small	Agg Transport-GS-Small	Transport-TR-1	General Service Large	Transport-TR-2	Customer Choice-GS-Large	Agg Transport-GS-Large	Transport-TR-3	Special Contract
1	2022 dist. main plant in service (Workpaper ALN-2)	196,127,120	124,495,061	17,818,796	11,944	22,529,343	5,321,700	1,588,420	4,977,428	1,814,106	11,621,281	70,016	76,249	5,345,382	457,395
2	2022 dist. main class allocation	1.000000	0.634767	0.090853	0.000061	0.114871	0.027134	0.008099	0.025379	0.009250	0.059254	0.000357	0.000389	0.027255	0.002332
3	MRP Revenue Requirement (Exhibit A-20)	\$2,756,827	\$1,749,944	\$250,467	\$168	\$316,680	\$74,804	\$22,327	\$69,964	\$25,500	\$163,353	\$984	\$1,072	\$75,136	\$6,429
4	2022 daily average customers (Exhibit A-16, Schedule F1.3)	182,332	146,650	21,110	7	11,364	2,737	252	109	54	40	3	2	3	1
5	Throughput (MCF) (Exhibit A-16, Schedule F1.3)	33,636,752	11,951,774	1,685,718	2,815	5,327,930	1,250,645	543,966	2,185,168	854,602	6,659,678	21,109	26,200	3,126,872	275
6	Average use per customer		81.5	79.9	402.1	468.9	456.9	2,158.6	20,047.4	15,835.0	166,492.0	7,036.4	12,058.6	1,042,290.7	274.8
7	Annual cost per customer		\$11.93	\$11.86	\$23.98	\$27.87	\$27.33	\$88.60	\$641.87	\$472.49	\$4,083.81	\$328.06	\$493.29	\$25,045.49	\$6,429.29
8	Monthly cost per customer		\$1.00	\$0.99	\$2.00	\$2.33	\$2.28	\$7.39	\$53.49	\$39.38	\$340.32	\$27.34	\$41.11	\$2,087.13	\$535.78